KERNFORSCHUNGSANLAGE JÜLICH GmbH
Programmgruppe Systemforschung
und Technologische Entwicklung

Angewandte Systemanalyse
Nr. 30

Summary Report on Technology Characterizations IEA, Energy Technology Systems Analysis Project

Edited by
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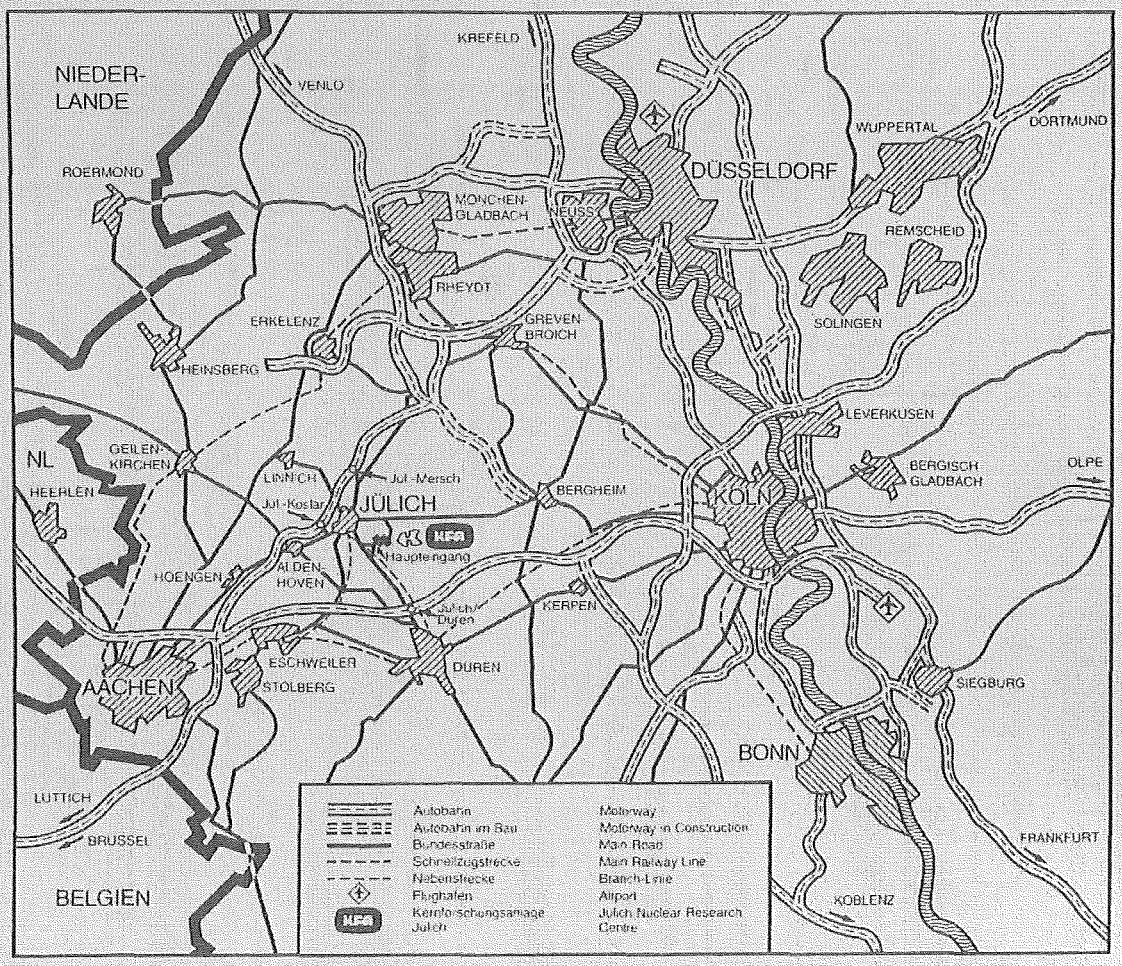
With Contributions of
St. Rath-Nagel, G.C. Tosato

Jül - Spez - 185
December 1982
ISSN 0343-7639



Als Manuskript gedruckt

Spezielle Berichte der Kernforschungsanlage Jülich – Nr. 185

Programmgruppe Systemforschung u. Technologische Entwicklung Jül - Spez - 185

Zu beziehen durch: ZENTRALBIBLIOTHEK der Kernforschungsanlage Jülich GmbH
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ABSTRACT

The report documents technical and economic information of energy technologies. The information has been assembled in seventeen IEA-countries, using common definitions for the calculation of each required datum. Additionally, detailed system descriptions have been provided that allow an analysis of the country specific differences in energy technology design and economics.

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PREFACE

The data and the technical information documented in this report were assembled for the "Energy Technology Systems Analysis Project" (ETSAP) of the International Energy Agency (IEA). The data collection which is the basis of this publication started in March 1981. Its intention was to focus on the technical properties and economics of new energy technologies. For this purpose, a set of questionnaire forms was developed, establishing common ground rules and definitions for the calculation of each required datum. The questionnaires were addressed to technical experts in industry, government agencies, research laboratories and universities. In November 1981, a technology workshop was held where the received material was reviewed. Objective of this workshop was to compare characterizations from different countries for similar technologies, wherever possible, and to search for explanations when differences among characterizations occured. At the same time, the workshop stimulated various activities to improve the provided material. This report summarizes the technology characterization work carried out from early 1981 to the end of 1982. The report is certainly not intended to be a compendium of energy technology systems. And it also doesn't claim to contain the only relevant information about energy technologies that can be obtained in the participating countries. It is, however, a summary of the best technical information presently available to energy technology systems analysts from 17 different IEA countries and the Commission of the European Communities. Detailed energy systems studies are carried out using the presented technology data as basis for the analysis. Therefore it is of vital interest for the project participants that the information documented in this report is not considered final. The report is rather intended as a status report which invites for further communication with technical experts and energy analysts who may contribute constructive criticism and complementary information.

ACKNOWLEDGEMENTS

The editors gratefully acknowledge the support and contribution of many people in the compilation of this report. They would like to thank all their colleagues and friends, especially at Kernforschungsanlage Jülich (KFA/STE) and at Lucas Heights Research Laboratories Sydney (Energy Division of CSIRO) where most of the work has been done. A special mention should be given to: Stefan Rath-Nagel for contributing essential parts of the 6th chapter of this report; Giancarlo Tosato for writing most of the 8th chapter; Douglas Hill and Mike Finnis for reviewing the collected material and providing helpful comments; Jenny Hickox, Cécile Rinchon and Maria Bischoff for very skillful secretarial assistance. The editors would like to take the opportunity of acknowledging in particular the valuable assistance of Peter Essam in editing this report. His insights into many fields of energy technologies have significantly contributed to review the technical information and to prepare the final version of this report.

Michael Müller, Kenneth J.Maher
(Editors)

1. INTRODUCTION

1.1 Technology Characterizations - Objectives and Milestones

In order to provide an analytic basis for energy research development & demonstration (RD&D) strategy, the International Energy Agency (IEA) initiated in 1976 an Energy Systems Analysis Project, in which initially fifteen IEA countries and the Commission of the European Communities participated. To carry out the assessment a flexible multi-period linear programming (LP) model, MARKAL (an acronym for "market allocation") was developed which could be readily adapted to describe the diverse national energy systems of the participating countries (Ref. 1.1). As a second essential element of the systems analysis work intensified efforts were started to assemble a data base adequately describing the existing energy system as well as the technical and economic parameters of potential components in a future energy system.

In order to compile data on individual technologies a set of questionnaire forms was developed for circulation to technical experts in industry, government agencies, research laboratories, and universities. The range of data items required to be entered on the forms went beyond the needs of the model in order to obtain as complete a picture as possible of the various technologies.

The material contained in the questionnaires was reviewed in discussions with the assessors. As a result of this review process the relevant group of technologies and data elements which appear in this report were determined. In addition, the Operating Agent of the Project included detailed system descriptions and added comments on each of the selected sources.

During the compilation of the report which is a successor of earlier publications (Ref. 1.2 to 1.4) a number of difficulties, which are generally associated with the task of technology characterizations, were encountered. The most

important of these are:

- o Unbalanced distribution of information, i.e. in some areas a large number of sources became available whereas in other areas very little information was provided.
- o Incomparability of the information due to differences in definitions of the data inherent to the sources.
- o Uncertainties in estimates of data elements, particularly in cost data of technologies which are subject to further development.

Where possible, the Operating Agent attempted to remove or at least mitigate these difficulties in close cooperation with the assessors. However, it must be recognized that limitations in time and manpower existed among many project participants which made it impossible to overcome these problems completely. It should also be acknowledged that because of the wide spectrum of energy technologies covered in the report, not every assessor including the Operating Agent could be an expert on every detail but had to rely on information and expertise provided by specialists. The reader should bear in mind that the report is not intended to be a compendium of energy technology systems and that it does not claim to be comprehensive or exclusive. It is, nevertheless, a summary of the best information presently available to the project participants.

1.2 Ground Rules

In order to facilitate direct comparisons of characterizations where this was appropriate, the technical and economic data of energy technologies were summarized in characterization summary tables. With the exception of the chapters describing selected residential and commercial technologies and transport devices, a common format has been used for this purpose (see Fig. 1.1).

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit										

Figure 1.1: Characterization Summary Table

Entries of the Summary Table

o Design Capacity

This is the net output capacity of the technology. For conversion and production technologies the net capacity generally will be the capacity given on the manufacturer's nameplate minus the internal consumption of the technology (expressed as capacity).

For the calculation all energy quantities are based on net calorific values (NCV) of fuel.

o First Commercial Service Year

Earliest year at which, under normal conditions, the technology could be expected to be commercially available and ready to operate with the technical characteristics and the costs given in the summary table.

If the system described is assumed to be a mature technology, this data must hence take into account the fact that prior experiences with commercial size demonstration plants is necessary.

Note: The abbreviation "c.a." stands for "currently available".

o Maximum Annual Energy Output
The total possible annual energy production (net) of the technology, under the assumption that a consumer is always ready to accept any output. Routine maintenance and unscheduled outages of the technology and, where appropriate, times of lacking resource (e.g. wind) are taken into account. All energy quantities are based on net calorific values (NCV) of fuel.

o Capacity Factor
The capacity factor of a technology is defined as ratio of the production (output), if operating at a realistic annual load pattern (i.e. considering the variation of the consumer's demand) over the output, if operating at the nominal capacity for 8760 h (365 days) per year.

o Maximum Annual Availability
Time (expressed in percentages of a year) where, based on statistical experiences, any energy production of the technology is possible upon the request of the consumer.
In the main the maximum annual availability during the plant lifetime is influenced by routine maintenance and unscheduled outages. But it is also determined by the unavailability of the input energy source (e.g. for wind energy conversion systems, wind flows with wind speeds lower than the cut-in wind speed of the system).

o Overall Efficiency (Average Load)
Ratio of annual production to annual fuel consumption, assuming the technology operates at a realistic annual load pattern, and also taking into account energy flows through the system which are too low to allow production (examples: start-up consumption of a thermal power plant: wind flows through wind energy conversion systems with velocities too low for production).
The calculation of the efficiency is based on net calorific values (NCV) of fuel.

o Total Capital Cost

Total capital costs cover construction cost, owner's cost, interest during construction and, where appropriate, also discounted cost for decommissioning the technology. All cost figures refer to the year of the first commercial service and are expressed in constant 1980 US dollars (annual average). Costs which were available from sources in other currencies and for a different price basis were, unless otherwise mentioned, converted for the summary table according to the following convention: first conversion to price basis 1980 and then conversion to dollars using average 1980 currency exchange rates. (For the conversion factors see Table 1.1.)

o Fixed Operating and Maintenance Cost

The manner in which O&M costs are split into fixed and variable components can be somewhat arbitrary and was left to the assessor.

The following items are covered: labour cost, cost of repairs, cost of replacement of parts, cost of non-fuel material consumption, cost of waste disposal (except for nuclear fuels), taxes, insurances.

o Variable Operating and Maintenance Cost

For content see comment to item 4.6.

Note: In some cases only one of both entries is given. In the summary table an arrow indicates ( ) when one data item is included in the other.

o Economic Lifetime

Time which the plant is expected to be operating at the capacity factor and at the costs given in the questionnaire and after which the plant is expected to be scrapped. It is hence the lifetime used to evaluate the product cost.

Note that the real lifetime could technically be longer than the economic lifetime, but this would generally imply a lower capacity factor and rising annual O&M costs, because of a higher rate of breakdowns and because of the necessity to replace the parts that have deteriorated.

When additional entries to the characterization summary table are made, they are explained in the respective chapters of this report.

Factors for Unit Conversions

o Capacity units: Multiple of W or J/a
Conversion: 1 W = 3.17 10^{-8} J/a

o Energy units: Multiple of Wh or J
Conversion: 1 Wh = 3600 J

TABLE 1.1 - GDP Deflators and Currency Exchange Rates

	Australian Dollar (Aus $)	Austrian Schilling (S)	Belgian Franc (Bfrs)	Canadian Dollar (Can $)	Danish Crown (Dkr)	German Mark (DM)	Greek Drachma (Dr)	Irish Pound (IR £)	Italian Lire (Lit)	Japanese Yen (Y)	Dutch Guilder (Hfl)	Norwegian Crown (Nkr)	Spanish Peseta (Ptas)	Swedish Crown (Skr)	Swiss Franc (Sfr)	U.K. Pound (£)	U.S. Dollar (US $)
1970	59.9	63.2	66.1		60.7	72.5	56.9	53.4	57.0	63.0	63.9	67.2	56.0	65.4	67.6	54.0	72.0
1971	63.0	68.6	69.7		65.5	78.0	58.7	59.0	61.1	65.8	69.4	71.9	60.5	70.2	73.7	58.8	75.7
1972	67.5	75.5	74.1		71.4	82.4	61.7	66.9	64.8	69.0	75.9	75.3	65.8	74.9	80.8	63.5	78.8
1973	74.2	82.6	79.2		78.7	87.4	73.6	77.1	72.4	77.0	82.3	82.2	73.5	80.1	87.4	68.2	83.3
1974	84.3	92.4	89.0	90.3	88.9	93.4	89.0	81.8	85.2	92.1	90.0	92.1	85.7	87.3	93.6	78.2	91.2
1975	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1976	114.9	106.7	107.5	109.5	109.2	103.3	115.6	120.3	118.0	105.6	108.9	107.5	116.7	111.9	102.7	113.5	105.1
1977	124.2	113.8	115.4	117.2	119.0	107.1	130.5	135.2	140.5	112.6	115.8	116.4	143.3	123.8	102.9	127.8	111.3
1978	133.0	119.6	120.2	124.7	130.0	112.1	147.6	148.8	160.0	117.8	121.8	124.9	172.3	136.4	106.7	142.2	119.4
1979	145.6	127.0	125.0	137.6	139.5	115.5	172.7	168.1	185.1	120.7	126.5	133.7	199.5	148.0	108.8	160.7	129.6
1980 (estimated)	161.3	135.0	133.4	152.2	157.8	121.3	215.4	198.6	222.8	124.4	134.9		230.3	167.0	112.0	190.0	141.2
1980 $ Average Annual Exchange Rate	0.876	12.93	29.21	1.168	5.631	1.816	43.33*	0.486	855.9	225.2	1.985	4.936	71.60	4.228	1.674	0.430	1

* at 30th September 1980

1.3 References

/1.1/ Rath-Nagel, St., Giesen, G., Hymmen, A., Maher, K., Müller, M., Vos, H.: "International Technology Assessment with the MARKAL Energy Model"; "Beyond the Energy Crisis, Opportunity and Challenge"; p. 149-159, Pergamon Press Oxford and New York, 1981

/1.2/ Manthey, Ch. (editor): "Energy Technology Data Handbook", Vol. I, Conversion Technologies, Jül-Spez-70 (Vol. I), Juni 1980

/1.3/ Manthey, Ch., Tosato, G.C. (editors): "Energy Technology Data Handbook", Vol. II, End-Use Technologies, Jül-Spez-70 (Vol. II), Oct. 1980

/1.4/ Sailor, V.L. (editor): "Technology Review Report", BNL 27074, Dec. 1979.

2. NON-NUCLEAR POWER PLANTS

2.1 Boiler-Fired Power Plants for Electricity Generation

2.1.1 Introduction

Electrical energy is generated by three stages in a boiler-fired power plant:

1. Conversion of the chemical binding energy to heat energy in the boiler, which is then transferred to some working fluid, usually water and/or steam.
2. Conversion of the heat energy of the working fluid to mechanical energy by a turbine.
3. Conversion of the mechanical energy to electrical energy by a generator.

Figure 2.1 shows how the boiler and turbine, together with a condenser and a pump, are integrated into a steam cycle. In the boiler, combustion heat is transferred to water in order to produce high-pressure, high-temperature steam. The steam then enters the turbine where the expansion of the steam to low-pressure and low-temperature steam in the turbine produces mechanical power. After the thermal energy of the steam has been converted to mechanical power, the discharged steam is condensed to water in a condenser. The water is then pumped back into the boiler, where the cycle starts again. The heat removed in the condenser is rejected to the environment either by direct cooling (e.g. cooling by fresh-water from rivers, lakes etc.) or by indirect cooling (e.g. evaporative cooling in a "wet" cooling tower, convective cooling in a "dry" cooling tower etc.) /2.1/*.

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* It should be noted here that the choice of the cooling system not only has major impact on the capital cost of the plant, but also on the overall efficiency of the energy conversion process. A steam cycle process with direct fresh water cooling has less exergy losses in the condenser, and therefore a higher overall efficiency than processes using evaporative or dry cooling systems.

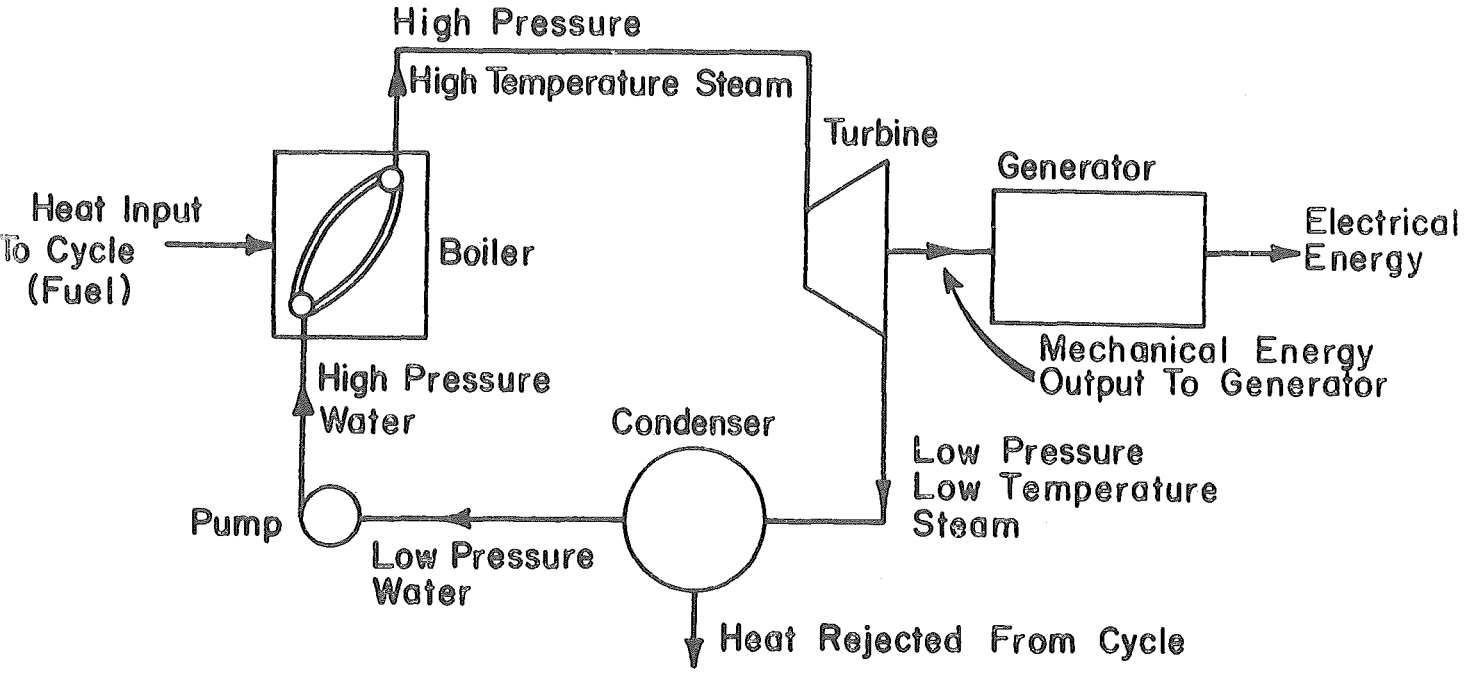

Figure 2.1: Simplified Steam Cycle /2.1/

In practice the steam cycle contains a number of components not shown in Figure 2.1. They provide an increase in the thermal efficiency of the process. Examples are:

1. A "superheater", in which the saturated steam is superheated in the boiler.
2. A "reheater", in which the partially expanded steam taken from earlier stages of the turbine is reheated, before returning to the turbine. In general the turbines are divided into three stages; a high-pressure, a medium-pressure, and a low-pressure stage.
3. An economizer, which extracts heat from the flue gas (after the superheater) and uses it to heat the water being fed to the boiler.

4. Regenerative feedwater preheaters in which the boiler feedwater is preheated by pressurized steam tapped from the turbine stages. The preheaters are termed "regenerative", because the steam for the preheating is circulating in a second cycle inside the thermodynamic steam cycle.

5. Air preheaters, which use heat extracted from the flue gas (after the economizer) to preheat the combustion air fed to the furnace.

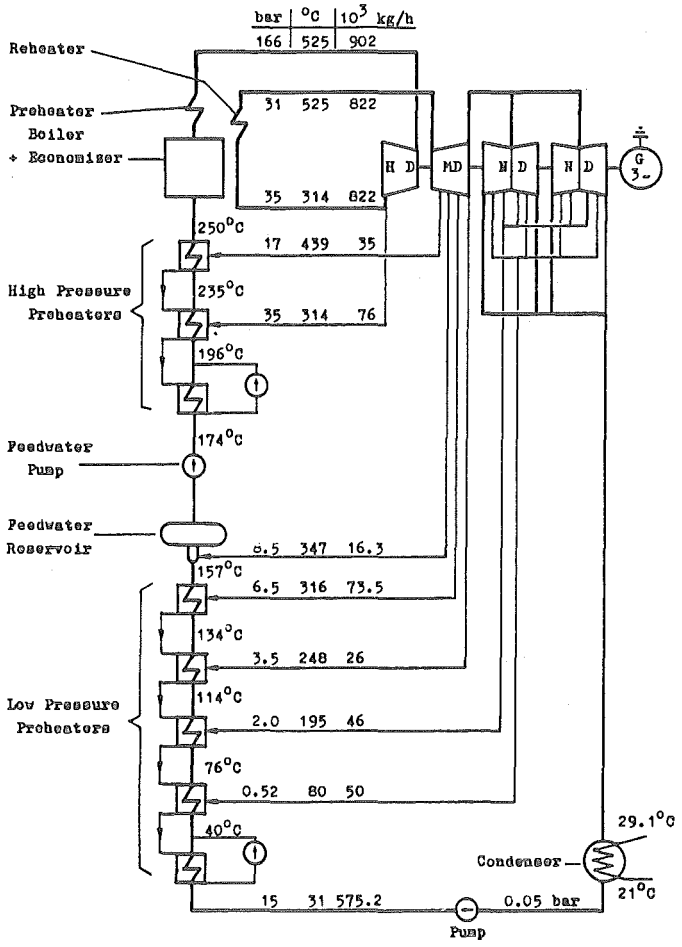

Figure 2.2: Circuit Diagram of a Modern Steam Cycle Power Plant

2.1.2 Conventional Boilers /2.1/

A number of variables affect conventional boiler design, the main one being the type of fuel to be burned. Oil and gas are both blown with the combustion air into the combustion chamber through nozzles in the fuel burners. The coal generally

has to be pulverized to a very fine powder before being burned. Additionally a number of problems have to be dealt with when burning coal; such as the formation of fly ash in the boiler and slagging which makes the removal of the combustion residuals more difficult.

Other important conventional boiler design variables affect the combustion pattern and temperature control. In some cases, the burners are directed vertically downward, an option used primarily with solid fuels. In the others, the burners are fired horizontally, in opposition, or tangentially along the walls of the furnace. In a frequently used technique (staged firing), 90 to 95 per cent of the air enters the boiler as primary or secondary air with the fuel before combustion, and the remainder enters as tertiary air through auxiliary ports in the furnace. Because of imperfect mixing, approximately 20 per cent more air (i.e. 120 per cent excess air) must be injected into the combustion chamber than is theoretically required for complete combustion.

A significant advance in conventional coal firing is the "cyclone" furnace, where crushed coal enters a horizontal cylinder at one end while air is injected tangentially along the cylinder periphery. This results in a cyclonic combustion pattern, which has the following advantages:

- reduction of fly ash content in the flue gas,
- saving in fuel preparation, since only crushing is required instead of pulverizing,
- reduction of furnace size.

2.1.3 Air Pollutants Generated by Conventional Boilers

Three major factors determine the amount and character of the air pollutants generated by a boiler: fuel burned, boiler design, and boiler operating conditions.

Sulphur oxides (SO_x) are directly related to the sulphur content of the fuel, and there is little in the way of conventional boiler design and operation that can affect this residual. Thus sulphur oxides must be dealt with either before or after burning. In electrical power generating stations the most effective way of sulphur control generally is by stack gas cleaning. More than 50 individual processes for removing SO_2 from stack gases are known, but the most effective appear to be "scrubbing processes" in which the stack gas is passed over or through a material that reacts with SO_2 to form a compound. The resultant compound is then either dumped or treated so that some useful form of the sulphur may be recovered (see also Fig. 2.3) /2.1/. However, the removal of sulphur oxides from the stack gas results in a lowering of the overall efficiency of the electricity generation process, as the scrubber absorbs steam and also electricity from the generating process. Although scrubber processes have been developed to a point of reasonable reliability and performance, their high operating and capital cost and a considerable waste disposal problem have initiated further development of so-called "regenerable" flue gas desulphurization systems. These regenerable systems employ various chemical processes to remove the SO_2 (either by wet or dry absorption) and then regenerate the original sorbent, usually giving a concentrated SO_2 by-product. The by-product is then converted to elemental sulphur or sulphuric acid. However, it must be noted that most of these systems are still under development and cannot be adequately evaluated, either technically or economically /2.2/.

Nitrogen oxides (NO_x), on the other hand, can be significantly affected by boiler design and operating conditions. Variables for fossil-fuelled boilers in controlling NO_x emissions are staged firing, low excess air (less than 110 per cent of the actual requirement for complete combustion), and flue gas recirculation. However, the process of NO_x creation during

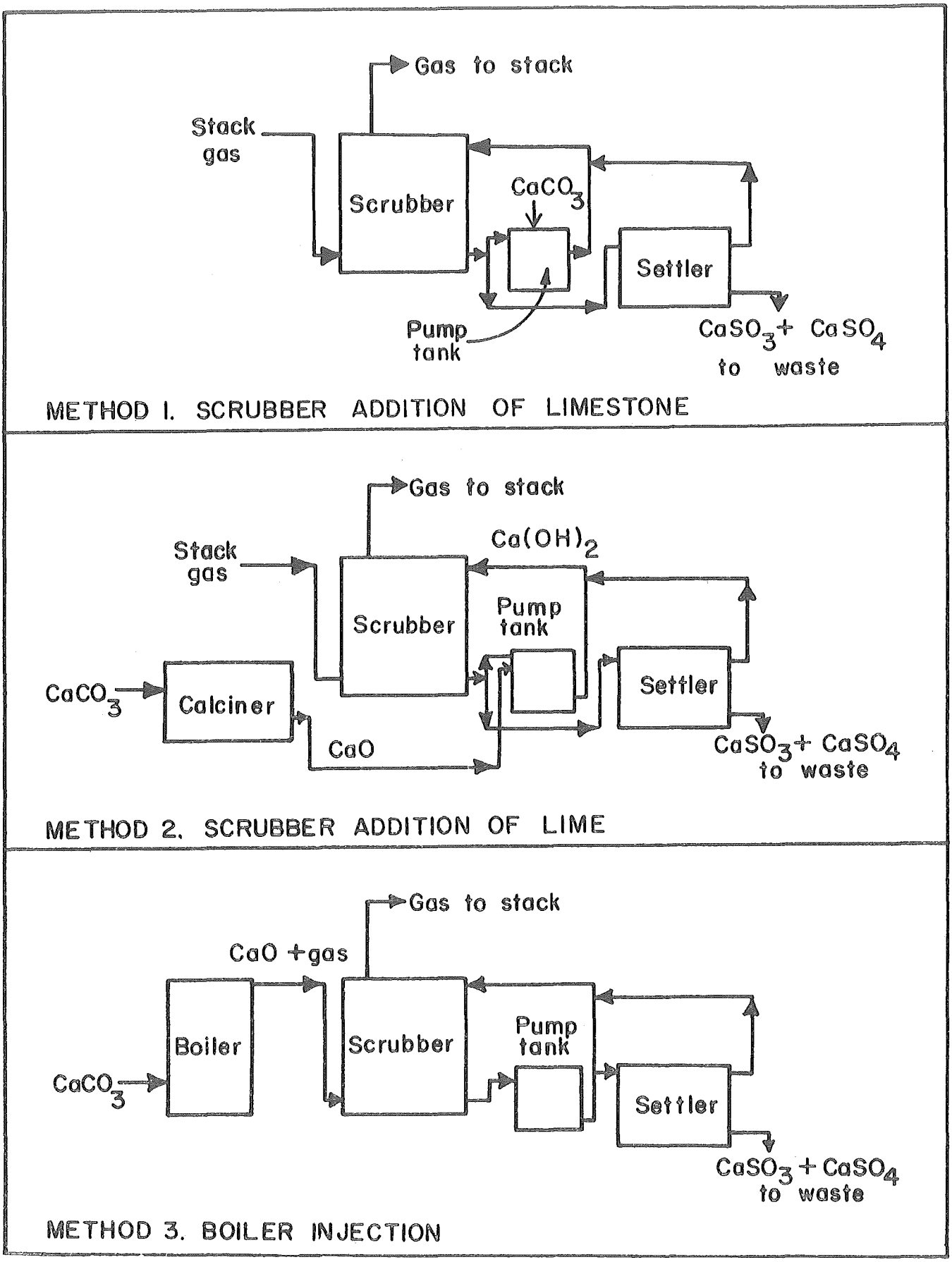

Figure 2.3: Methods of Stack Gas Cleaning in a Scrubbing Process /2.1/.

combustion is not yet completely understood*.

Another major problem with coal-fired boilers are particulate emissions. As already mentioned, improved boiler design (cyclone furnace) can reduce the formation of fly-ash during combustion. In addition particulates can be removed from the stack gas, either mechanically in irrigated or dry cyclones or in electrostatic precipitators.

2.1.4 Conventional Boiler-Fired Steam Power Plants - Characterization Summary

Eight characterizations of conventional boiler-fired power plants were submitted by the project participants. These were (country name in brackets):

(1) Hard Coal/Oil-Fired Steam Power Plant (Denmark)
Base load plant, with a direct freshwater cooling system, without flue gas desulphurization.

(2) Hard Coal Steam Power Plant (Germany)
Medium load power plant, with evaporative natural draft cooling towers, with flue gas desulphurization (scrubber).

(3) Hard Coal Steam Power Plant (Japan)
Base load power plant, with a direct fresh water (sea water) cooling system, with flue gas desulphurization (scrubber).

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* Basically two mechanisms are responsible for the creation of nitrogen dioxides. The first mechanism is the creation of nitrogen oxides from the nitrogen compounds in the fuel; the second is the creation of so-called thermal nitrogen oxides from the combustion air or the combustion gases. The latter mechanism starts above temperatures of about 1600 °C.

In principle it should be noted here that the shortcomings in understanding the process of NO_x creation render more difficult the application of the above mentioned methods for NO_x control. Nevertheless, in addition to the correct choice of the boiler parameters there is still the possibility of removing NO_x directly from the stack gas either by ammonia or potash washing.

(4) Coal-Fired Steam Power Plant, Bituminous Coal (U.S.A.)
Base load power plant, with evaporative natural draft cooling towers, without flue gas desulphurization.

(5) Coal-Fired Steam Power Plant, Bituminous Coal (U.S.A.)
Base load power plant, with evaporative natural draft cooling towers, with flue gas desulphurization (scrubber).

(6) Hard Coal Steam Power Plant (from IEA/EAS sources)
Base load power plant, with evaporative natural draft cooling towers, with 85 % flue gas desulphurization.

(7) Brown Coal Steam Power Plant (Germany)
Base load power plant, with evaporative natural draft cooling towers, without flue gas desulphurization (FGD) system.

(8) LNG Steam Power Plant (Japan)
Base load power plant, with a direct freshwater (sea water) cooling system.

TABLE 2.1 - Technical and Economic Key Data of Conventional Boiler-Fired Power Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable C&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/kW_e	$/kW_e	$/GJ	Yrs
Denmark (Coal/Oil)	610	1981	14.4	67	75	39	495	6.5	0.23	35
Germany (Hard Coal)	1298	c.a.	36.8	45.7	90	34	789	28	0.94	20
Japan (Hard Coal)	910	c.a.	23.0	70	80	35.2	901.6	56.5	0.64	20
U.S.A. (Bituminous Coal, without FGD)	800	c.a.	19.4	60	77	36.5	850	23.8	0.41	30
U.S.A. (Bituminous Coal, with FGD)	800	c.a.	18.9	60	75	35.4	1000	36.3	1.00	30
IEA/EAS sources	1000	c.a.	25.2	65	80	34.4	960	→	2.60	30
Germany (Brown Coal)	1140	c.a.	32.3	85	90	34	849	29.5	0.19	20
Japan (LNG)	965	c.a.	24.3	70	80	40	577.5	36.5	0.33	20

Assessors

Coal/Oil Power Plant - Christensen, C.J., Riso, Roskilde, Denmark

Hard Coal Power Plant - Walbeck, M. and Martinsen, D., KFA/STE, Postbox 1913, 5170 Jülich, FRG

Hard Coal Power Plant - Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki, Japan

Bituminous Coal Power Plant (without FGD) - Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

Bituminous Coal Power Plant (with FGD) - Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

Hard Coal Power Plant - Müller, M. (from IEA/EAS source), KFA/STE, Postbox 1913, 5170 Jülich, FRG

Brown Coal Power Plant - Walbeck, M. and Martinsen, D., KFA/STE, Postbox 1913, 5170 Jülich, FRG

LNG Power Plant - Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-mura, Ibaraki, Japan

Notes:

(1) All energy quantities are based on NCV of fuels. The following list shows the NCVs on which the calculations have based:

TABLE 2.2 - Net Calorific Values of Fuels

Country	Fuel	NCV
Denmark	Hard Coal	23.8 GJ/t
Germany	Hard Coal	29.63 GJ/t
Japan	Hard Coal	24.66 GJ/t
U.S.A.	Bituminous Coal	not specified
(IEA/EAS)	Hard Coal	25.68 GJ/t*
Germany	Brown Coal	8.4 GJ/t
Japan	LNG	50.11 GJ/t

* Calculated from GCV = 26.75 GJ/t, assuming a NCV/GCV conversion factor of 0.96

(2) Capacity Factor

Except for the German hard coal power plant (CF = 45.7 %) all power plants listed in the characterization summary are base-load power plants (CF = 60-85 %).

TABLE 2.3 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being		Unit
			Less Than	Greater Than	
Denmark	Overall Efficiency	39	38	40	%
(Coal Oil)	Total Capital Cost	495	450	540	$/kW$_e$
	Fixed O&M Cost	6.5	5	8	$/kW$_e$
	Variable O&M Cost	0.23	0.17	0.28	$/GJ
	Economic Lifetime	35	30	40	yrs
U.S.A.	Overall Efficiency	36.5	34.4	37.5	%
(without	Total Capital Cost	850	725	975	$/kW$_e$
FGD)					
U.S.A.	Overall Efficiency	35.4	33.3	36.5	%
(with FGD)	Total Capital Cost	1000	850	1150	$/kW$_e$

(4) Overall Efficiency (Average Load)

The wide variation in efficiency is essentially caused by the different construction of either the cooling and/or the flue gas desulphurization (FGD) system of the power plants. Accordingly the efficiencies of hard coal power plants vary from 39 % for the Danish sytem without FGD and a direct fresh-water cooling to 34.0 % for the German system with a scrubber and an evaporative natural draft cooling tower (for explanation see sections 2.1.1 and 2.1.3).

(5) Total Capital Cost

Table 2.4 shows the breakdown of construction costs for a hard coal steam power plant, as given in three different sources (General Electric, Bechtel, KEC).

TABLE 2.4 - Construction Costs for a Hard Coal Power Plant /2.3/

	Estimator		
Plant Item	General Electric	Bechtel	KEC
Coal handling	13.9	8.7	17.3
Ash handling	9.8	3.7	10.5
Boiler	142.1	157.7	102.3
Turbo-generator	57.3	72.0	61.9
Electrostatic precipitator	17.5	40.7	17.6
Scrubber	103.4	129.2	80.3
Cooling tower	13.5	(1)	18.0
Pumps, pipes, condenser etc.	101.8	105.0	107.5
Electrical, instrumentation, etc.	68.0	77.7	97.0
Civil, yardwork, etc.	72.7	109.2	80.9
TOTAL	601.1	703.9	593.4

(1) not given separately

(2) all costs expressed in mid-1980 $/kW$_e$

The wide range of the capital costs essentially depends on whether a flue gas desulphurization system is included or not. Changing the cooling system, on the other hand, does not play such an important role as its construction costs are smaller than the uncertainty associated with scrubbers and boilers. Except for the Danish figures, the estimates of the capital costs in the characterization summary clearly reflect the influence of different design and uncertainties in the estimates.

Against that, the Danish figure for the capital costs of a coal/oil-fired power plant seems remarkably low. However, it has been confirmed that the Danish electricity utilities indeed calculate their implementation program for a new generation of coal/oil-fired power plants with the stated cost.

(6) Operating and Maintenance Costs

The operating and maintenance costs were arbitrarily split into fixed and variable costs. So a direct comparison of O&M costs is only meaningful on the basis of the total O&M costs. Table 2.5 shows the total O&M costs of the characterized power plants. It has been assumed that the power plants are operating at the capacity factor stated in the summary table.

One conclusion drawn from the comparison is that power plants with a FGD system generally have much higher O&M costs than systems without scrubbers. Nevertheless, this does not explain the very low cost figure for the Danish oil/coal power plant compared with German, IEA/EAS, and U.S. estimates.

TABLE 2.5 - O&M Costs of Conventional Boiler-Fired Power Plants

Country	O&M Cost
Denmark (Coal/Oil)	0.54 $/GJ
Germany (Hard Coal)	2.88 $/GJ
Japan (Hard Coal)	3.20 $/GJ
U.S.A. (Bituminous Coal, No FGD)	1.67 $/GJ
U.S.A. (Bituminous Coal, FGD)	2.92 $/GJ
IEA/EAS (Hard Coal)	2.60 $/GJ
Germany (Brown Coal)	1.29 $/GJ
Japan (LNG)	1.98 $/GJ

Another feature is that the O&M costs of the Japanese power plants (hard coal with FGD, LNG) usually are higher than the costs of comparable systems of other countries. This reflects the fact that in the Japanese characterizations miscellaneous costs for the administrative infrastructure of the electricity utilities (overheads) and annual taxes are included in the O&M costs. This procedure has not been followed in the other characterizations.

(7) Economic Lifetime

The variation in the estimates of the economic lifetimes mainly reflects the different understanding of the definition of the economic lifetime. Some assessors understood it as financial lifetime (usually 20 years), others as amortization or technical lifetime (30-35 years).

2.1.5 Fluidized Bed Boilers

The desire to reduce pollutants as well as to improve boiler efficiency has led to increased work on the boiler technologies. One of the results of these efforts is the fluidized bed boiler concept.

In a fluidized bed boiler air is passed upward through a grid plate which supports a thick bed of granular, non-combustible material such as coal ash or lime. The air lifts and keeps the granular particulates suspended (the "fluidized" state) and, with the relatively small amount of air used to inject the fuel (mainly coal), it serves as the combustion air. The heat transfer surfaces or boiler tubes can be embedded in the fluidized bed because combustion occurs at temperatures (appr. 850 °C) that do not damage the tubes /2.1/.

Fluidized bed boilers have some adavantages over conventional boilers, the first and most important one being the possibility of controlling sulphur dioxide during combustion. For this purpose crushed limestone (or dolomite) is injected into the fluidized bed, where it is calcinated.

$$Ca\ CO_3 = Ca\ O + CO_2$$

Subsequently, the lime reacts with oxygen and the sulphur dioxide in the fluidized bed, forming calcium sulphate.

$$Ca\ O + SO_2 + 1/2\ O_2 = Ca\ SO_4$$

The degree of desulphurization depends on the molecular ratio of absorbent to sulphur. Ideally, a desulphurization of more than 95 % can be achieved, if the ratio is adjusted correctly. In practice, however, the creation of the absorbent, i.e. the calcination process, is the crucial step in the desulphurization process. The major determinant is the porosity of the lime particles formed in the calcination process, as the large surface area of the porous material promotes the reaction.

Different limestones vary widely in their calcination properties, a factor that appears to be decisive in the absorption efficiency of any particular limestone. At high temperatures the limestone is calcinated to lime which is completely unreactive due to its collapsed pores and recrystallized structure ("dead-burned" limestone).

Another important factor is the pressure under which the combustion takes place. At atmospheric pressure limestone calcination proceeds quite readily but at several atmospheres pressure and normal boiler temperature the reaction is retarded. Dolomite, a mixture of calcium and magnesium carbonates, which calcinates at lower temperature, even under pressure, is a much more efficient sorbent for pressurized fluidized bed boilers /2.2/.

A second advantage of fluidized bed boilers are the low combustion temperatures (about 850 °C). At these temperatures thermal nitrogen dioxides formation does not take place. Hence, flue gases from FBC boilers contain considerably less NO_X effluents than are released from conventional boilers.

As already mentioned above, there are basically two major concepts for designing fluidized bed boilers. These are

- the atmospheric fluidized bed boilers (AFB)
- the pressurized fluidized bed boilers (PFB)

The PFB promises advantages in efficiency as it combines a gas turbine and a steam turbine cycle, giving an increase in overall efficiency 5 %.

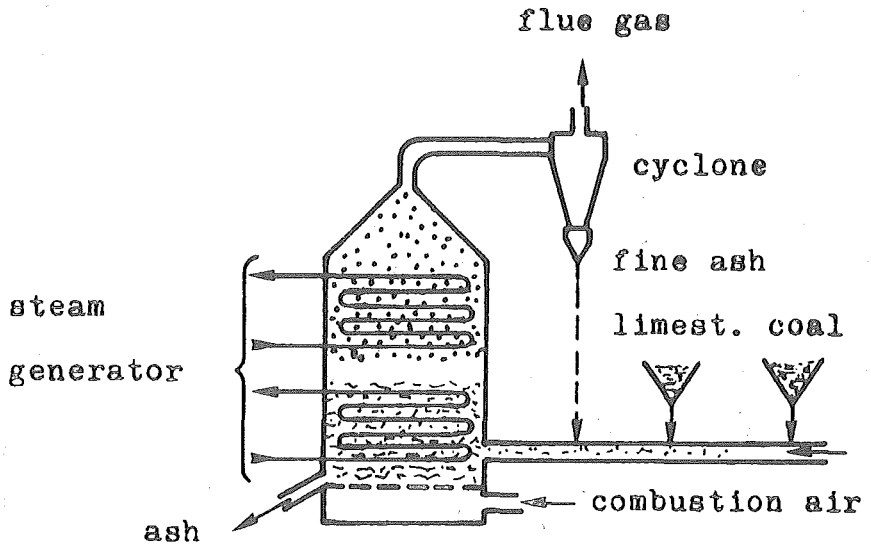


Figure 2.4: Fluidized Bed Boiler

Figure 2.5 shows such a combined cycle system, the Westinghouse pressurized fluidized bed combined cycle power plant (see also section 2.1.9). It is designed to burn coal in a dolomite bed at 10 atmospheres pressure. The water is initially heated to steam in the walls of the combustor and is then superheated in the beds. The steam drives a conventional turbine in a thermodynamic steam cycle. The combustion gases, after particulate removal, are used to drive a gas turbine and the heat remaining in the gas turbine exhaust is used to preheat the boiler feedwater. The spent dolomite is regenerated.

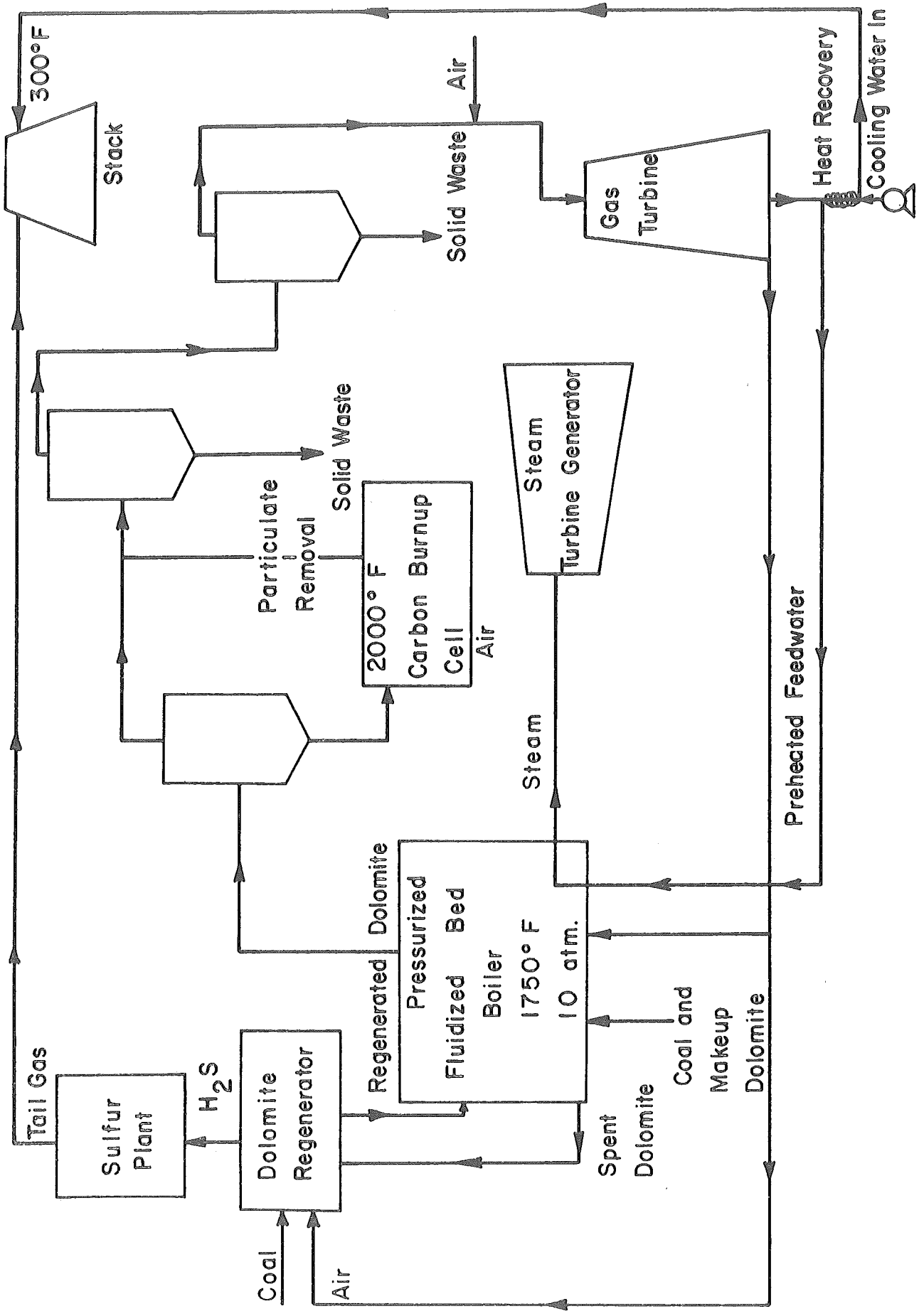


Figure 2.5: Westinghouse Pressurized Fluidized Bed Boiler Power Plant /2.1/

2.1.6 Fluidized Bed Power Plants - Characterization Summary

Five characterizations of power plants with a fluidized bed boiler were provided by the project participants. These are (country name in brackets):

(1) Atmospheric Fluidized Bed Power Plant (U.S.A.)
Coal-fired base load power plant, with evaporative natural draft cooling towers.

(2) Atmospheric Fluidized Bed Power Plant (from IEA/EAS sources).
Base load power plant, with evaporative natural draft cooling towers.

(3) Pressurized Fluidized Bed Power Plant (Sweden)
Coal-fired base load power plant, combined cycle concept, direct freshwater cooling.

(4) Pressurized Fluidized Bed Power Plant (U.S.A.)
Westinghouse concept, base load power plant with evaporative cooling towers

(5) Pressurized Fluidized Bed Power Plant (from IEA/EAS sources)
Base load power plant, with evaporative cooling towers, Westinghouse combined cycle concept.

TABLE 2.6 - Technical and Economic Key Data of Fluidized Bed Boiler Power Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/kW_e	$/kW_e	$/GJ	Yrs
U.S.A. (AFB)	600	1993	14.6	60	77	36.5	900	41.41	1.31	30
IEA/EAS sources (AFB)	1000	1990	25.2	65	80	37.3	745.2		2.25	30
Sweden (PFB)	500	1989	12.6	75	80	41	850	18.0	1.0	25
U.S.A. (PFB)	1000	1998	23.7	60	75	40.6	975	33.2	1.1	30
IEA/EAS sources (PFB)	1000	1995	25.2	65	80	40.8	865		2.49	30

Assessors

AFB Power Plant:- Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

AFB Power Plant:- M. Müller (from IEA/EAS sources), KFA/STE, Postbox 1913, 5170 Jülich, FRG.

PFB Power Plant:- Leman, G., Energy R & D Commission, Sweden

PFB Power Plant:- Bhagat, N., NCAES, Brookhaven National Laboratories, U.S.A.

PFB Power Plant:- Müller, M. (from IEA/EAS sources), KFA/STE, Postbox 1913, 5170 Jülich, FRG.

Notes:

(1) All energy quantities are based on NCV of fuels. In the IEA/EAS characterizations the NCV of 25.68 GJ/t for hard coal has been calculated from the originally given GCV = 26.75 GJ/t assuming a NCV/GCV conversion factor of 0.96. The conversion factor has been determined from the elementary analysis of an East-American-Coal (Pittsburgh seam bituminous). In the other characterizations, the NCV's were not specified explicitly.

(2) Table 2.7 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being		Unit
			Less Than	Greater Than	
U.S.A. (AFB)	Maximum Annual Availability	77	70	85	%
	Overall Efficiency	36.5	35.4	37.5	%
	Total Capital Cost	900	825	1000	$/kW$_e$
Sweden (PFB)	Total Capital Cost	850	790	950	$/kW$_e$
U.S.A. (PFB)	Maximum Annual Availability	75	70	85	%
	Overall Efficiency	40.6	38.5	42.7	%
	Total Capital Cost	975	875	1150	$/kW$_e$

(3) Overall Efficiency (Average Load):

The efficiency figures clearly reflect the advantage, that PFB systems with a combined steam and gas turbine cycle have over AFB systems. Within the range, pressurized fluidized bed power plants are approximately 4 % more efficient than equivalent atmospheric fluidized bed power plants.

(4) Total Capital Cost

For both AFB and PFB power plants the range of capital cost estimates is rather wide. This reflects the uncertainty in cost estimates for a technology which is not commercially available. Table 2.8 shows the breakdown of the construction cost, which forms the major part of the total capital cost.

TABLE 2.8 - Breakdown of Construction Cost of Atmospheric and Pressurized Fluidized Bed Power Plants

Technology	AFB	PFB	
Assessor	General Electric	General Electric	Westinghouse
Coal and limestone/ dolomite handling and feeding	38.4	65.3	56.0
Spend bed cooling and handling	13.9	12.1	19.6
Boilers (AFB, PFB)	96.1	40.0	47.7
Steam turbo generator	54.7	45.3	42.7
Gas cleanup	33.9	113.3	62.5
Cooling tower	9.1	7.6	22.3
Pipes, pumps, etc.	67.3	87.9	82.0
Electrical, instr. and control	75.6	65.3	50.3
Civil, structural, yardwork	70.6	58.2	66.4
TOTAL (without architect/ engineer's fee and contingency)	459.7	538.7	496.1

All costs in mid-1980 $/kW$_e$

(5) Operating and Maintenance Cost

Table 2.9 gives the total O & M cost for the fluidized bed systems presented in this report. The technologies have been assumed to operate with the capacity (load) factor given in the characterization.

TABLE 2.9 - Total O & M Cost of Fluidized Bed Power Plants

System	Country	Total O & M Cost
AFB	U.S.A.	3.50 $/GJ
AFB	IEA/EAS	2.25 $/GJ
PFB	Sweden	1.76 $/GJ
PFB	U.S.A.	2.85 $/GJ
PFB	IEA/EAS	2.49 $/GJ

It is noticeable that the American characterizations have considerably higher O & M cost for the atmospheric fluidized bed system than for the pressurized fluidized bed concept. This is opposite to the IEA/EAS assessment.

2.2 Binary Cycle Power Plants

2.2.1 Introduction

The primary disadvantage of steam cycle power plants described previously is their low thermal efficiency. A way of improving this is to combine two or more heat engine cycles covering different parts of the temperature range. Such a combination of two cycles is commonly referred to as binary cycle. Generally there are two basic possibilities for designing a binary cycle system, the first one being a system where the

second cycle is added to the high-temperature end of the primary cycle. This design is referred to as "topping" binary cycle system. A second cycle added to the low-temperature end of the primary cycle is termed a "bottoming" or "tailing" cycle.

At present only combined gas turbine/steam turbine systems - the so-called "combined cycle power plants" - play an important role in the electricity generation. In these systems, the hot exhaust from the gas turbine is used to generate steam in an unfired boiler. The steam then drives a conventional steam turbine.

Topping cycles using liquid metals are also being investigated. The principle advantage of using liquid metals (mercury, potassium) as working substance in power plants is their high boiling or vapourizing temperatures combined with relatively low vapour pressures. The efficiency of the liquid-metal Rankine cycle by itself is not very high. By using the condenser for the liquid metal as a boiler for water which circulates in a binary cycle, however, higher efficiencies of the overall process can be achieved.

2.2.2 Combined Cycle Power Plants - Characterization Summary

Three characterizations of combined cycle power plants were provided by the project participants. These were (country name in brackets):

(1) LNG Combined Cycle Power Plant (Japan)
LNG fired base load power plant, with a direct freshwater cooling system.

(2) Hard Coal Combined Cycle Power Plant (U.S.A.)
The hard coal is gasified to a low quality gas, which is then burned in the combustion turbine. The sulphur control

of the process consists in removing the sulphur oxides from the low BTU gas before it enters the combustion turbine. The residues of this gas cleaning then are reprocessed to elementary sulphur in a Claus-process.
Base load power plant, with evaporative natural draft cooling towers.

(3) Gas Combined Cycle Power Plant (U.S.A.)
Gasified medium load power plant. Further details not specified.

TABLE 2.10 - Technical and Economic Key Data of Combined Cycle Power Plants

Technology	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/kW_e	$/kW_e	$/GJ	Yrs
LNG Combined Cycle Power Plant	1000	1990	25.2	70	80	54.3	632.3	39.7	0.24	20
Coal Combined Cycle Power Plant	800	1992	18.9	60	75	39.6	1050	40.1	1.21	30
Gas Combined Cycle Power Plant	500	c.a.	13.4	35	85	46.7	470	15.8	0.8	30

Assessors:

LNG CC Power Plant:- Koyama, S., Kashihara, T., Endo, E.,
Electrotechnical Laboratory, Sakura-Mura,
Ibaraki, Japan

Hard Coal CC Power Plant:- Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

Gas CC Power Plant:- Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

Notes:

(1) All energy quantities are based on the fuel NCV. Orginally the calculations in the American characterizations were based on GCV. For the characterization summary table the original American efficiency estimates have been recalculated assuming the following NCV/GCV conversion factors:

Hard Coal: NCV/GCV = 0.96
Gas: NCV/GCV = 0.9

(2) TABLE 2.11: Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being		Unit
			Less Than	Greater Than	
U.S.A. (Coal C.C)	Maximum Annual Availability	75	70	85	%
	Overall Efficiency	39.6	37.5	41.7	%
	Total Capital Cost	1050	900	1300	$/kW$_e$
U.S.A. (Gas C.C)	Overall Efficiency	46.7	43.3	50	%
	Total Capital Cost	470	425	525	$/kW$_e$
	Fixed O&M Cost	15.8	10.0	20.0	$/kW$_e$
	Variable O&M Cost	0.8	0.5	1.0	$/GJ$_e$

(3) Overall Efficiency (Average Load):

The combined cycle systems summarized in table 2.7 are not directly comparable as the feedstock of the coal combined cycled power plant is a solid fuel which has to be gasified

before being burned in a gas turbine. This decreases the process overall efficiency compared with a combined cycle system fuelled by a gaseous or liquid fuel. Nevertheless, the overall efficiency of U.S. hard coal combined cycle power plant is still higher than the efficiency of equivalent conventional power plants. The rather uncomplicated sulphur control and the general capability of combined cycle systems to follow faster load changes than conventional boiler-fired power plants gives the impetus to promote the development of CC power plants for coal basis - even if their advantages in efficiency are small.

(4) Total Capital Cost:

The higher capital costs of the hard coal combined cycle power plant compared to the gas systems are caused by the additional installation of a coal gasification stage and a Claus-unit for reprocessing sulphur oxide residues from the gas cleaning process.

(5) Operating and Maintenance Cost:

The total operating and maintenance cost have been calculated assuming that the technologies operate at the capacity factor (load factor) given in the characterization summary table:

TABLE 2.12: Total O & M Cost

Technology	Total O & M Cost
LNG C.C. Power Plant	2.04 $/GJ
Coal C.C. Power Plant	3.33 $/GJ
Gas C.C. Power Plant	2.23 $/GJ

A comparison of the total O & M cost shows the additional operating costs of the coal combined cycle power plant for gasification and the subsequent sulphur removal from the raw gas. However, the difference between the O & M cost of the coal power plant and those of the two gas systems is even larger than the values indicated in table 2.1. The O & M cost figure of the Japanese LNG system includes miscellaneous costs for administration, buildings etc. (overheads) and annual taxes. This is a procedure which has not been followed in the American characterizations. Furthermore, the O & M cost of the American gas C.C. power plant have been calculated with a capacity factor of just 35 % (medium load operation), while the other power plants operate as base loaded electricity generators. If the gas power plant also operated as base load power plant (CF = 60 %), the total O & M cost be 1.64 $/GJ. This shows that a direct comparison of the absolute figures in table 2.12 should be treated carefully.

2.3 Magnetohydrodynamic (MHD) Power Plants

2.3.1 Introduction

An MHD generator produces electrical energy directly from thermal energy and has the potential for conversion efficiencies of 50 to 60 %. The higher conversion efficiency results primarily from the high temperature at which MHD generators operate and from bypassing a heat energy to mechanical energy conversion step.

MHD generators work on similar principles to conventional electricity generators, in which a coil spins inside a set of magnets. In an MHD generator the stationary conductor is replaced by a moving, electrically conductive fluid. This conductive fluid flows through a duct which is immersed in a magnetic field produced by a superconducting magnet. The fluid movement through the duct induces a voltage drop across the fluid stream. The electrodes of the MHD generator are normally two opposite walls of the duct. Electrical leads are attached to the walls to supply the electrical load. Note that MHD systems generates DC power which has to be converted to AC power if the generator feeds into an AC grid.

Three basic types of MHD systems can be distinguished:

1. Open-Cycle Plasma System
   Fossil fuel is burned at a sufficiently high temperature (2200 to 2750 °C) to ionize the product gases. The electrical conductivity of the ionized gases is increased by "seeding" them with readily ionized material, generally salts of potassium or cesium. The hot gases then pass through the MHD generator and subsequently heat a conventional steam cycle. The seed material is extracted from the flue gas and recycled to the ionization stage.

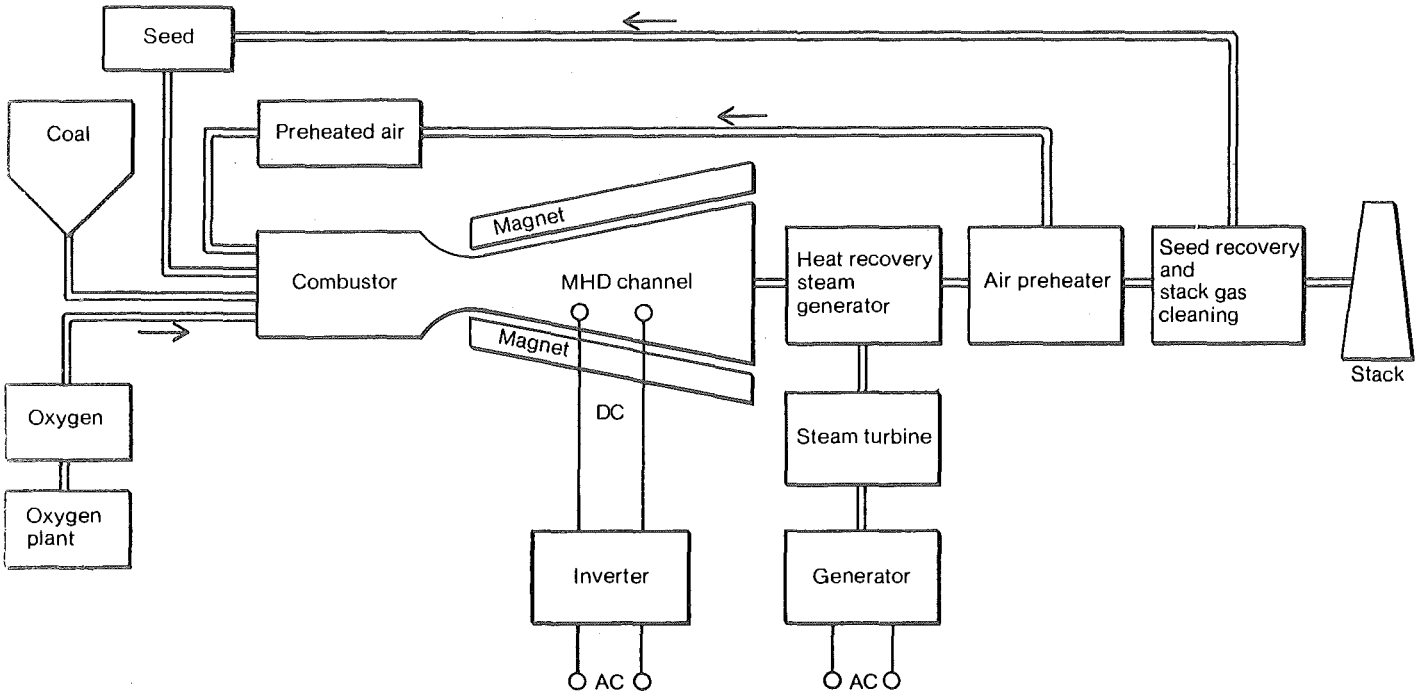


Figure 2.6: MHD Power Plant - Open-Cycle Plasma System /2.4/

2. Closed-Cycle Plasma System

The closed-cycle plasma system uses a seeded noble gas (helium or argon) which is indirectly heated (e.g. in a fossil fuel boiler). The hot gas passes through the MHD generator, is then cooled down and subsequently compressed for reheating. A closed-cycle plasma system requires a heat source operating over the range of 1250 to 1900 °C.

3. Liquid Metal MHD System

The liquid metal MHD system consists of two fluid circuits, a liquid metal and an inert gas circuit. The liquid metal is indirectly heated (e.g. nuclear or fossil boiler), and the inert gas is then dispersed into the liquid metal. As the gas expands, due to being heated by the liquid metal,

the two fluids accelerate through the MHD generator, the liquid metal providing the moving conductor capability. At the exit of the MHD generator, the two fluids are separated. The liquid metal is reheated and the gas is cooled and recompressed before being remixed with the liquid metal /2.1/.

2.3.2 MHD Power Plants - Characterization Summary

Two characterizations of MHD power plants have been provided by the project participants. These are (country name in brackets):

(1) Hard Coal MHD Power Plant (Japan)
Base load power plant with a direct freshwater (sea water) cooling system. Open-cycle plasma system with a steam bottoming cycle.

(2) Hard Coal MHD Power Plant (U.S.A.)
Open-cycle plasma system with a steam bottoming cycle. The system is equipped with an evaporative cooling tower.

TABLE 2.13 - Technical and Economic Key Data of MHD Power Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/kW_e	$/kW_e	$/GJ	Yrs
Japan	1000	2010	25.2	70	80	50.6	1152	71.9	1.10	20
U.S.A.	1000	2005	22.1	60	70	49	1400	32.25	0.52	30

Assessors

Japan:- Koyama, S., Kashihara, T., Endo, E.,
Electrotechnical Laboratory, Sakura-Mura, Ibaraki

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory

Notes:

(1) All energy quantities are based on NCV of fuels.

(2) Overall Efficiency (Average Load)

The difference in the efficiency reflects the impact of different cooling system design (freshwater cooling (Japan); evaporative cooling in natural draft cooling towers (U.S.A.)).

(3) TABLE 2.14 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being Less Than	10 % Probability of Being Greater Than	Unit
U.S.A.	Maximum Annual Availability	70	60	80	%
	Overall Efficiency	49	45.8	52	%
	Total Capital Cost	1400	1100	1700	$/kWe

(4) Operating and Maintenance Cost

Assuming the MHD power plant operates at the capacity factor given in the summary table, the total O&M costs of the Japanese system is 4.36 $/GJ, while the O&M costs of the American system are about half that value (2.22 $/GJ). One reason for this discrepancy is that in the Japanese characterization, overheads (expenditures for administrative labour, buildings, etc.) and annual taxes are included in the O&M cost.

2.4 Fuel Cell Power Plants

2.4.1 Introduction

In a fuel cell, electrical energy is produced directly from a controlled electrochemical oxidation of fuel. Since fuel cells do not require an intermediate heat cycle, they are not limited by the Carnot cycle efficiency and therefore have a theoretical efficiency approaching 100 per cent. The basic components of a simple hydrogen-oxygen fuel cell are the electrodes (anode and cathode) and an electrolyte which may be either acidic or basic. The reactants in the cell are normally consumed only when the external circuit is completed, allowing electrons to flow and the electrochemical reaction to occur. The result is good fuel efficiency even with low or intermittent loads.

When the external circuit is completed, an oxidation reaction yielding electrons takes place at the anode and a reduction reaction requiring electrons occurs at the cathode. The electrodes provide electrotechnical reaction sites and also act as conductors for electron flow to the external circuit. Power is produced as long as fuel and oxidant are supplied to the fuel cell and the external electrical circuit is closed, allowing current to flow. Continuous operation necessitates the removal of heat (see also section 2.5), water and any inert material that enter the cell with the reactants. Reaction kinetics usually are enhanced by the incorporation of a catalyst such as platinum on high surface area electrode surfaces. The power produced from fuel cells is direct current (DC) and thus must be converted to alternating current (AC) for use in a conventional electric power system /2.1/.

There are three main classifications of fuel cells, depending on the type of fuel used:

1. Hydrogen-Oxygen Fuel Cell
   The operation of such a fuel cell has been described above.

2. Hydrocarbon-Oxygen Fuel Cell
   This type of fuel cell uses gaseous hydrocarbons directly in a phosphoric acid electrolyte fuel cell.

3. Reformer Fuel Cell
   Coal or other hydrocarbons are reformed (reacted with steam) to produce a fuel that primarily consists of hydrogen and carbon monoxide. This fuel then is used in a phosphoric acid electrolyte fuel cell or in a more advanced molten carbonate electrolyte fuel cell (at a higher temperature of appr. 1200 °C).

2.4.2 Fuel Cell Power Plants - Characterization Summary

Three characterizations have been submitted by project participants. These are (country name in brackets):

(1) Phosphoric Acid Electrolyte Fuel Cell (U.S.A.)
Distillate or other liquid or gaseous hydrocarbons are reformed to a hydrogen rich gas, which is used in a phosphoric acid electrolyte fuel cell. The process as described includes the transformation of DC power to AC power.

(2) Molten Carbonate Acid Electrolyte Fuel Cell (U.S.A.)
Fuelled as the system described above. The hydrogen rich gas then, however, is used in a high-temperature molten carbonate electrolyte fuel cell. The transformation of DC power to AC power is included in the overall process.

(3) LNG Fuel Cell Coupled Production Plant (Japan)
LNG is used in a phosphoric acid fuel cell, which produces both electricity and heat for district heating purposes. The system will be discussed in detail in section 2.5 and therefore is not contained in the characterization summary.

TABLE 2.15 - Technical and Economic Key Data of Fuel Cell Power Plants

	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/$kW_e$	$/$kW_e$	$/GJ	Yrs
Phosphoric Acid Electrolyte Fuel Cell Power Plant	10	1987	0.278	30	88	43	700	10.8	1.1	20[X]
Molten Carbonate Electrolyte Fuel Cell Power Plant	10	1992	0.284	30	90	49	600	10.8	1.1	20[X]

* The cell stack must be replaced every 4 1/2 years. It is not clear whether this has been considered in the estimates of the O&M costs.

Assessor

Bhagat, N., NCAES, Brookhaven National Laboratory, U.S.A.

Notes:

(1) According to the the conventions of this report, all energy quantifics are based on NCV of fuels. For the fuel cell inputs, a NCV to GCV conversion factor of 0.9 has been assumed.

(2) TABLE 2.16 - Uncertainty Ranges

Technology	Item	Median Value	10 % Probability of Being Less Than	10 % Probability of Being Greater Than	Unit
Phosphoric Acid Electrolyte Fuel Cell Power Plant	Overall Efficiency	43	41	45.5.	%
	Total Capital Cost	700	550	1200	$/kW$_e$
Molten Carbonate Electrolyte Fuel Cell Power Plant	Overall Efficiency	49	45.5	52	%
	Total Capital Cost	600	475	825	$/kW

(3) Overall Efficiency (Average Load)

The difference between the efficiencies of the two fuel cell systems shows the advantage of a high-temperature fuel cell (molten carbonate electrolyte) over a "conventional" phosphoric acid electrolyte fuel cell.

2.5 District Heating

2.5.1 Introduction

When a fuel is burned, energy is available in the form of heat at a high-temperature level. This energy form can then be converted to other forms such as mechanical energy, electrical energy, etc. These conversion processes (heat engines) are limited by the fact that the heat can be used provided its temperature remains above ambient levels. For this reason conventional steam cycles for electricity generation only reach efficiencies of about 35 to 40 %. Approximately 60 % of the energy produced is rejected to the environment in the form of low-temperature heat as warm water from the cooling system and hot flue gases.

On the other hand, there is a considerable demand for low-temperature heat, especially for space and warm water heating in the residential and commercial sector. Therefore, the direct use of the large quantities of reject heat at low temperature levels from heat engines is a promising option. This not only improves the thermal efficiency of the individual process; it is also an important key for the substitution of primary fuels (especially the replacement of oil), which traditionally have a large share in the production of low-temperature useful energy.

A prerequisite to the direct use of low-temperature heat is the development of a suitable heat transportation and distribution system. A key parameter for such a system is the maximum initial feed temperature. This has to be chosen in such a way that the overall system operates economically. As the temperatures for space heating and warm water are at the temperature level of the reject heat from heat engines, a high conversion efficiency could be achieved if heat is transported and distributed on the low-temperature level. On the other hand, the pipelines for the low-temperature heat transport highly capital

intensive.Investigations of the overall economics of large district heating systems show that the best economic efficiency of the system can be achieved with maximum initial feed temperatures of about 180 °C. Higher temperatures are not recommended as the corresponding evaporation pressures also increase. This renders the pressure control in the grid more difficult.

2.5.2 Back-Pressure Turbine Coupled Production Process

The overall efficiency of a heat engine can be improved by using a large part of the rejected heat for heating purposes at a low-temperature level. Technically this can be done in two different ways, one being the "back-pressure" turbine and the other being the "pass-out" turbine (refer to 2.5.2 for the latter). In a back-pressure turbine coupled production system, the expansion of the superheated steam is stopped at a low pressure level and the steam is used for other purposes such as district heating. Thus in a back-pressure system the fairly large low pressure stage of the turbine and the condensation unit (including the cooling system) is no longer needed. This makes back-pressure coupled production units smaller and cheaper than pure electricity generation units. The back-pressure steam taken from the turbine passes through a heat exchanger, where it delivers its heat (including its evaporation heat) to a heating fluid (e.g. water), which is circulating in a district heating system. The steam cycle condensate is then pumped back to the boiler where it is reheated.

It should be noted that taking steam from the plant at a higher-than-normal pressure and temperature level, the Carnot-cycle efficiency of the steam cycle is decreased and part of the possible electricity generation is sacrificed for heat production.

In back-pressure systems, heat and electricity are generated in a fixed ratio. In most cases the electricity is considered as the byproduct of the process heat production.

It should be clearly noted that it is economically not reasonable for a back-pressure turbine coupled production plant only to produce one output, e.g. process heat, without also generating the second output. Nevertheless, in most of the back-pressure systems a reduction unit is assigned as by-pass for the turbine. In case of need the superheated steam can thus be discharged without passing through the turbine. This produces pure heat generation, and the system has to be supplied with electrical power from the grid. Pure electricity generation, on the other hand, is generally not possible with back-pressure turbine coupled production systems, as they are normally not equipped with a back-up cooling system in which the discharged steam could be condensed in case of too low a heat transfer in the heat exchanger.

2.5.3 Back-Pressure Turbine (BPT) Coupled Production Plant - Characterization Summary

Three characterizations of back-pressure coupled production systems have been provided. These are (country name in brackets):

(1) Hard Coal Back-Pressure Turbine Coupled Production Plant (Belgium)
District heating plant, equipped with a fluidized bed boiler.

(2) Coal/Oil-Fired Back-Pressure Turbine Coupled Production Plant (Denmark)

(3) Hard Coal Back-Pressure Turbine Coupled Production Plant (Germany)
District heating plant, 100 % stack gas desulphurization.

(4) Wood Waste Fired Cogeneration of Electricity and Heat (Austria)

TABLE 2.17 - Technical and Economic Key Data for BPT Coupled Production Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	$\frac{MW_{el}}{MW_h}$	-	$\frac{TJ_{el}}{TJ_h}$	%	%	%	$/kW_{tot}$	$/kW_{tot}$	$/GJ_{tot}$	Yrs
Belgium	$\frac{28}{91}$	c.a.		45		87	216	3.39	0.14	25
Denmark	$\frac{87}{174}$	1983	$\frac{2744}{5487}$	58	80	89	364	6	0.17	30
Germany	$\frac{37}{76}$	c.a.	$\frac{1020}{2040}$	60.5	85	73	372	30.1	0.36	20
Austria	$\frac{3}{5.8}$	c.a.	$\frac{88.9}{172}$		94	88	534	6.8	0.15	18

Assessors

Belgium:- Altdorfer, F., Services Programmation de la Politique Scientifique, Rue de la Science 8, B-1040 Brussels

Denmark:- Christensen, C.J., Riso, Roskilde

Germany:- Walbeck, M., Martinsen, D., KFA-STE Jülich, Postbox 1913, D-5170 Jülich

Austria:- Pönitz, E., Energieverwertungsagentur, 1010 Wien, Opernring 1

Notes:

(1) The indices of the units in the summary table have the following meaning:

el = electricity
h = heat
tot = total = electricity + heat

(2) All energy qualities are based one NCV of fuels. The following list shows the NCVs used in the characterizations.

	NCV of Coal
Belgium	- not specified
Denmark	23.7 GJ/t
Germany	29.3 GJ/t
Austria	- not specified

(3) TABLE 2.18 - Uncertainty Ranges

Country	Item	Medium Value	10 % Probability of Being Less Than	10 % Probability of Being Greater Than	Unit
Denmark	First Comercial Service Year	1983	1983	1985	-
	Maximum Annual Availability	80	74	83	%
	Capacity Factor	58	54	60	%
	Overall Efficiency	89	87	91	%
Austria	Maximum Annual Availability	94	80	96	%
	Overall Efficiency	88	79	91	%
	Economic Lifetime	18	15	20	yrs

(4) Costs Data

In the summary table all cost figures have been related to the direct sum of heat and electricity capacities or outputs. That is, both outputs are considered to be "equally valuable". The simple additive approach has been chosen to allow a quick recalculation of the cost figures, if one of the very divergent and controversial "rating methods" is preferred. Table 2.12 shows the result of such a recalculation assuming that in a coupled production plant electricity is energetically twice as valuable as process heat. This strategy is based on the fact that roughly only one third of the thermal energy in a power plant is converted into electricity whereas two thirds are available as heat.

TABLE 2.19 - Recalculated Cost Figures of BPT Coupled Production Plants

Country	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	$/kW*	$/kW*	$/GJ*
Belgium	175	2.74	0.105
Denmark	273	4.5	0.1275
Germany	280	22.6	0.27
Austria	398	5.1	0.11

Index: * = heat + 2 * electricity

(5) Fixed Operating & Maintenance Cost

The high fixed O&M cost of the German system are caused by the expenses for operating labour amounting to 21.3 $/kw$_{tot}$, approximately 70 % in the fixed O&M costs. The high labour costs are under investigation.

2.5.4 Pass-Out Turbine Coupled Production Plants

The main disadvantage of back-pressure coupled production units is the lack of flexibility, especially in following divergent demands for electricity and heat, because its heat and electricity can only be generated in a fixed ratio. This limits the application of the BPT technology to process heat production with by-product electricity. Consequently the BPT option is not of much interest to electricity utilities.

A minor change in steam cycle design, however, makes the enormous quantities of rejected heat in large steam cycle electricity generation units available without sacrificing control and load following capabilities of the plant.

As already mentioned in section 2.1, steam can be passed out of the turbine at several places. In a conventional power plant this steam is used for purposes such as regenerative feed water preheating or driving the boiler feed water pump. But it could also be passed through a heat exchanger to deliver its energy to a heating fluid circulating in a district heating system. Systems in which this process is applied are called pass-out turbine (POT) coupled production systems. The basic advantage of the POT concept is that electricity and heat can be gene-

rated in a variable ratio (see Figure 2.7), which makes possible load following at varying electricity and heat demands.

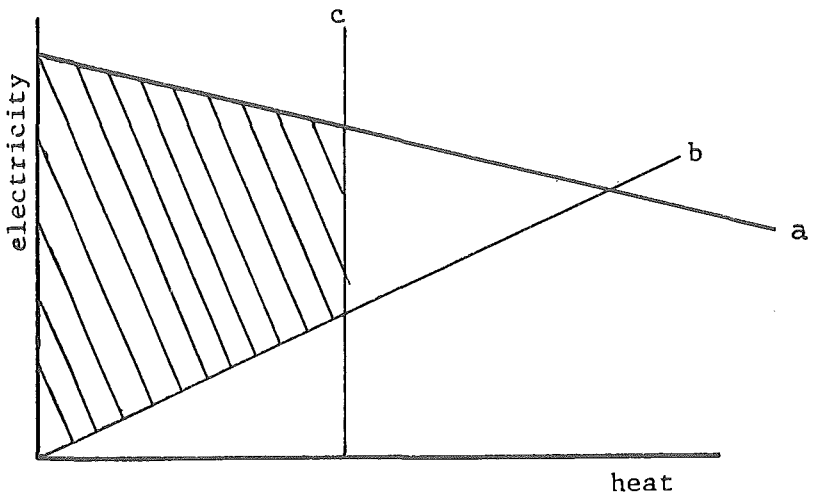


Figure 2.7: Output Characteristic of a POT Coupled Production Plant

It should also be noted that in POT systems the production of process heat means sacrificing a part of the electricity output. However, the turbine design sets a practical limit on the maximum electricity which can be sacrificed to produce heat, as in operation there must be enough steam passing through the low pressure stage of the turbine to provide necessary rotor cooling (line "b" in Figure 2.7). Another practical limit is given by the size of the heat exchanger which is designed only for a certain quantity of steam (line "c" in Figure 2.7). Together with the maximum feasible quantity of superheated steam passing through the high pressure stage of the turbine (line "a" in Figure 2.7) these limits bound the work area (shaded) of a pass-out turbine coupled production unit.

2.5.5 Heat from the Exhaust of Internal Combustion Engines or Gas Turbines

Internal combustion engine or gas turbine processes in which the thermal energy in the combustion gases is converted into mechanical or electrical energy, offer nearly the same heat availability as steam cycle systems. Only about one third of the energy is converted in these engines, while a large part of the remaining energy leaves the engine or turbine as exhaust heat at a fairly high temperature level. This heat can be used for such purposes as:

- combustion air preheating,
- heating of the feed water in a combined cycle process,
- district heating,

thus increasing the overall efficiency of the engines.

The main advantage of internal combustion engine or gas turbine coupled systems is their compact design which makes possible their economical use in decentralized district heating systems, large buildings (like hospitals) or other units with a lower heat demand. At the same time electricity is generated as a by-product of the heat production decreasing dependence on the electricity utilities.

2.5.6 Combustion Engine and Turbine Coupled Production Systems - Characterization Summary

Three characterisations of combustion engine/turbine coupled production systems have been provided. These are (country name in brackets):

(1) Gas Turbine Coupled Production Plant (Belgium)
Gas or light distillate oil-fired district heating plant with electricity cogeneration.

(2) Diesel Coupled Production Plant (Belgium)
Diesel engine coupled production plant for district heating.

(3) Total Energy System (Germany)
Small gas combustion engine system for the cogeneration of electricity, district heat (90 °C) and warm water (30 °C), consisting of 8 separate units with a capacity of 155 kW_{th} each. Designed for the application in a decentralized district heating system or large office buildings, hospitals etc.

TABLE 2.20 - Technical and Economic Key Data of Engine/Turbine Coupled Production Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	$\frac{MW_{el}}{MW_h}$	-	$\frac{TJ_{el}}{TJ_h}$	%	%	%	$/kW_{tot}	$/kW_{tot}	$/GJ_{tot}	Yrs
Gas Turbine Coupled Production Plant - Belgium	$\frac{25.3}{110}$	c.a.	-	45		77	107	2.69	0.134	25
Diesel Engine Coupled Production Plant - Belgium	$\frac{28}{28}$	c.a.	-	45		78	332	7.2	0.57	25
Total Energy System - Germany	$\frac{0.72}{1.11}$	c.a.	$\frac{19.3}{29.8}$	51	85	81	262.5	15.4	←	11.5

Assessors

Belgium:- Altdorfer, F., Services Programmation de la Politique Scientifique, Rue de la Science 8, B-1040 Brussels

Germany:- Müller, M., KFA-STE Jülich, Postbox 1913, D-5170 Jülich

Notes:

(1) The indices of the units in the summary table have the following meaning:

el = electricity
h = heat
tot = total = electricity + heat

(2) All energy quantities are based on NCV of fuels.

(3) Design Capacity

Besides the production of electricity and district heat, warm water at a temperature of 30 °C is also produced by the German total energy system. The warm water production capacity amounts to 214 kW.

This allows a maximum warm water supply of 5.73 TJ per annum. If the production of warm water is taken into account in the efficiency calculation, the overall efficiency of the total energy system increases to 91 %.

(4) Cost Data

All cost figures are related to the direct sum of electricity and heat capacity or output. Table 2.21 shows the cost figures assuming the value of the electricity is rated twice the value of the heat. For explanations see section 2.5.3, note (4).

(5) Uncertainty ranges for the data entries were not specified.

TABLE 2.21 Recalculated Cost Data of Engine/Turbine Coupled Production Plants

	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	$/kW*	$/kW*	$/GJ*
Gas Turbine	90.1	2.27	0.113
Diesel Engine	221.3	4.8	0.38
Total Energy System	118.4	11.1	

Index: * = heat + 2 * electricity

(6) Operating and Maintenance Costs

Assuming the coupled production plants are operating at the capacity factor given in the characterization summary, the total O&M costs, expressed as variable O&M costs, result in

- 0.273 $/GJ for the gas turbine coupled production plant
- 0.718 $/GJ for the diesel engine driven coupled production system
- 0.690 $/GJ for the gas engine driven total energy system

The O&M cost for combustion engine coupled production plants is higher than for the turbine systems. This is the result of the necessary maintenance servicing of combustion engines. However, it can be expected that improvements in engine technology will increase the maintenance servicing and help to reduce costs.

(7) Economic Lifetime

The economic lifetime of the German total energy system represents the financial average of a 50 year lifetime for the building and a 10 year lifetime for the technical devices.

2.5.7 Other Coupled Production Systems

Besides the described options of heat recovery from steam cycle and engine/turbine processes for district heating purposes, there exists many more possibilities for the cogeneration of electricity and heat. All non-boiler-fired power plants, like fuel cell or MHD power plants, are basically suited for coupled production. The Japanese delegation from the Electrotechnical Laboratory, Sakura-Mura, Ibaraki, investigated and assessed an LNG fuel cell coupled production plant.

In the electrolytical process of a fuel cell a considerable quantity of low temperature heat is produced. Instead of rejecting this heat to the environment, it can just as well be used for heating purposes. Electricity and heat are then produced in a fixed ratio, just like in a back-pressure turbine process. Table 2.13 shows the economic and technical key data given in the Japanese characterization of the LNG phosphoric acid electrolyte fuel cell system, which is scheduled to operate as a decentralized coupled production unit.

TABLE 2.22 - Technical and Economic Key Data of an LNG Acid Phosphoric Fuel Cell Coupled Production Plant

	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	$\frac{MW_{el}}{MW_h}$	-	$\frac{PJ_{el}}{PJ_h}$	%	%	%	$/kW$_{tot}$	$/kW$_{tot}$	$/GJ$_{tot}$	Yrs
	$\frac{20}{13.5}$	1990	$\frac{0.505}{0.341}$	80	80	71.7	618.2	68.5	0.638	20

Assessors

Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki, Japan

Notes:

(1) The unit indices in the summary table have the following meaning:

el = electricity
h = heat
tot = total = electricity + heat

(2) All energy quantities are based on NCV of fuels.

(3) Cost Data

All cost data are related to the direct sum of electricity and heat capacity respectively output. Table 2.23 shows the costs assuming that electricity is energetically twice as valuable as low-temperature heat. Recalculations under other assumptions can be performed in the same way. For explanation see section 2.5.3.

TABLE 2.23 - Recalculated Cost Data of the LNG Fuel Cell Power Plant

Total Capital Cost	Fixed O&M Costs	Variable O&M Costs
387.1 $/kW*	42.9 $/kW*	0.4 $/GJ*

Index: * = heat + 2 * electricity

(4) Operating and Maintenance Costs

The O&M costs include the expenses for the exchange of fuel cell components (lifetime: 5 years) during the plant's lifetime of 20 years.

(5) Uncertainty ranges for data entries were not specified

A common feature of the coupled production systems described above is that the heat recovered from the different processes is at or above the temperature level needed for heating purposes. However, lower level heat can be made available by utilizing heat pump technology. Such a heat source is a sewage treatment plant, in which large quantities of sewage at a nearly constant temperature level (7 - 13 °C) are available.

The Danish project participant described a heat pump system driven with a 3 MW diesel which extracts heat from the sewage of a 20 000 inhabitants community (300 - 1200 m^3/hr). To improve the system efficiency, the waste heat from the exhaust of the diesel engine, from oil and air cooler etc. also serves as heat source. Over a gearbox an electric generator is connected to the driving shaft of the engine in order to make possible cogeneration of electricity. Figure 2.8 shows the complete process diagram of the diesel heat pump coupled production plant. The process heat generated by the system is used first to increase the incinerator capacity of the refuse treatment plant, and second to supply a district heating system (90 °C/50 °C) as base load heating plant. The technical and economic key data of the system are summarized in table 2.24.

TABLE 2.24 - Technical and Economic Key Data of the Diesel Heat Pump Coupled Production Plant

	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	$\frac{MW_{el}}{MW_h}$	-	$\frac{TJel}{TJh}$	%	%	%	$/kW$_{tot}$	$/kW$_{tot}$	$/GJ$_{tot}$	Yrs
	$\frac{0.7}{11.3}$	1981	$\frac{342}{21}$	80	95	150	279	18	+	15

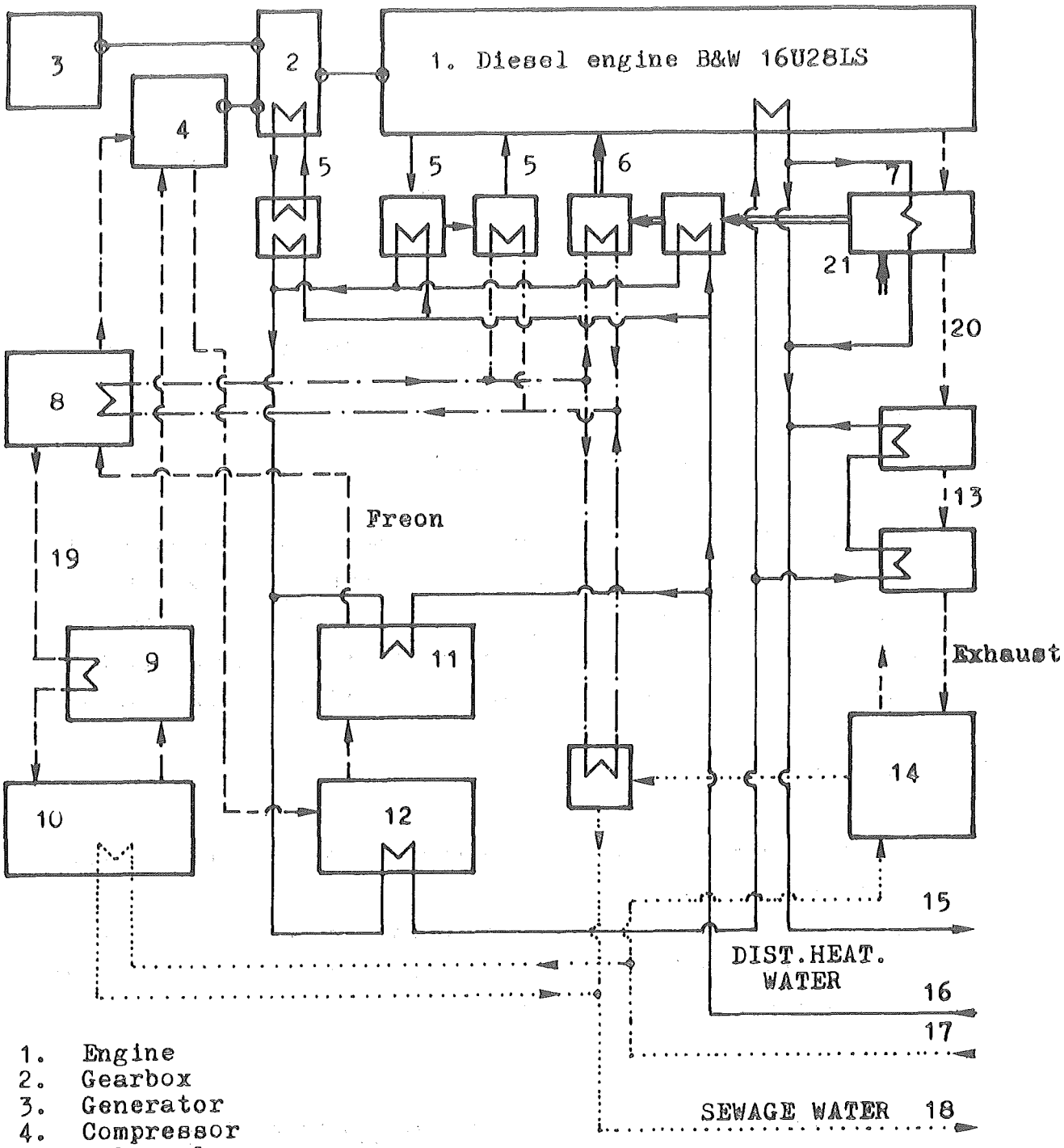
Assessor

Christensen, C.J., Riso, Roskilde, Denmark.

Notes:

(1) The unit indices in the summary table have the following meaning:

el = electricity
h = heat
tot = total = electricity + heat



1. Engine
2. Gearbox
3. Generator
4. Compressor
5. Oil cooler
6. Air cooler
7. Turbocharger
8. Economizer
9. Superheater
10. Evaporator
11. Subcooler
12. Condensator
13. Exhaust heat exchangers
14. Exhaust washer
15. District heating water
16. Return water
17. Purified sewage water
18. Used sewage water
19. Freon
20. Exhaust gas
21. Air

Figure 2.8: Process Diagram

(2) For the heavy fuel oil (diesel) fed to the diesel engine, an NCV of 40.68 GJ/t has been assumed.

(3) Design Capacity

Figure 2.9 shows the energy balance for the heat pump coupled production system.

(4) Overall Efficiency (Average Load)

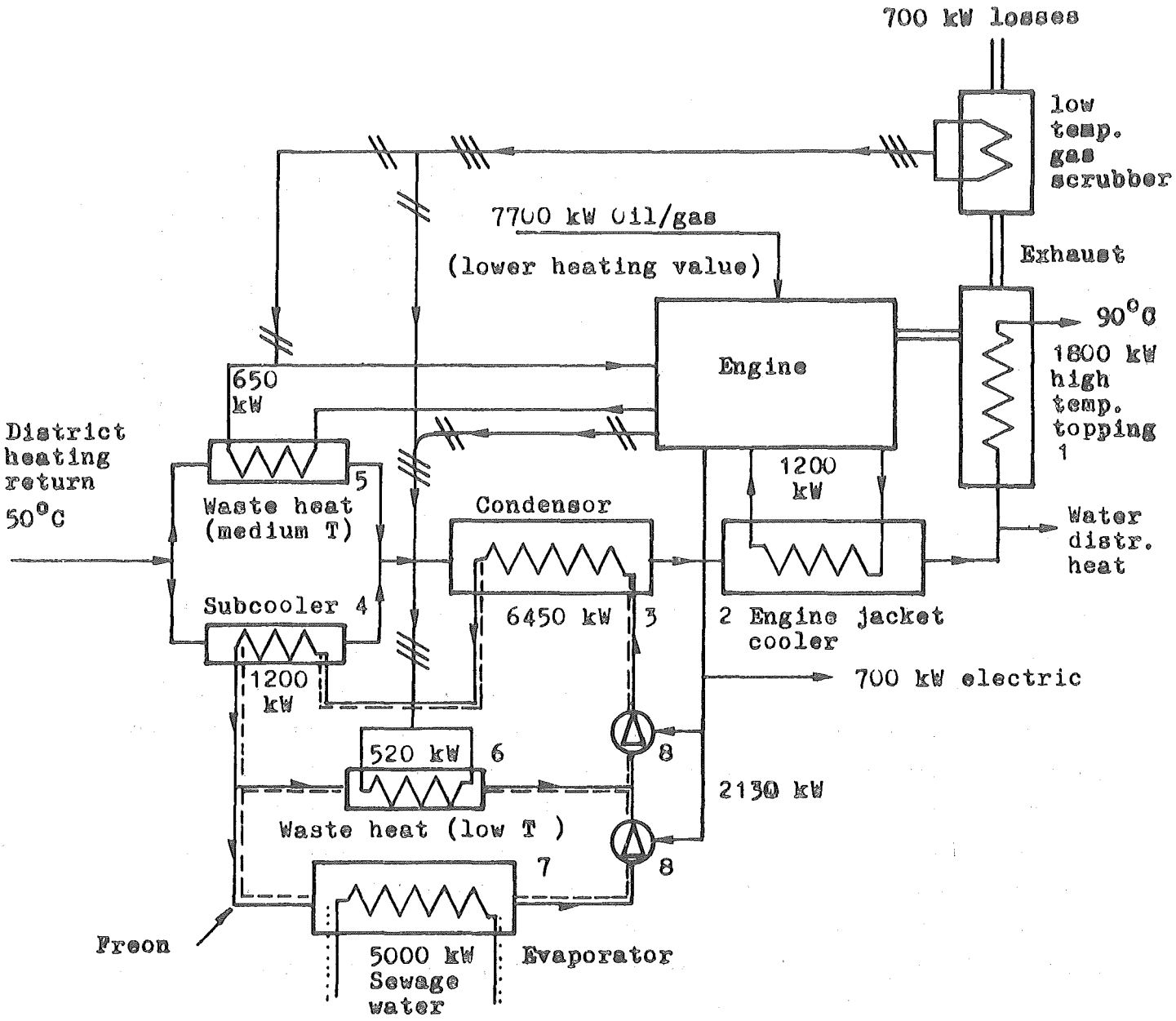
The overall efficiency (average load) has been calculated as the ratio of the average annual output of heat + electricity divided by the respective input of heavy fuel oil. Note that the energy content of the sewage (160 TJ/yr) has not been rated for the efficiency calculation.

(5) Cost Data

All cost data are related to the sum of electricity and heat capacity or output.
Table 2.25 shows the costs assuming the energetic value of the electricity is rated twice the value of the heat. For explanation see section 2.5.3.

TABLE 2.25 - Recalculated Cost Data of the Heat Pump Coupled Production

	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	$/kW*	$/kW*	$/GJ
	248	16	



1. Waste heat recovery from exhaust gas
2. Waste heat recovery from jacket cooler
3. Heat pump condenser
4. Undercooling of liquid refrigerant
5. Mean temperature waste heat from engine
6. Low temperature waste heat
7. Evaporator with heat from energy reservoir
8. Compressors

Figure 2.9: Energy Balance for Diesel Heat Pump Equipped with Power Generator

(6) TABLE 2.26 - Uncertainty Ranges

Item	Medium Value	10 % Probability of Being		Unit
		Less Than	Greater Than	
Maximum Annual Availability	95	90	98	%
Capacity Factor	80	65	95	%
Total Capital Cost	279	210	350	$/kW$_{tot}$
Fixed O&M Cost	18	9	36	$/kw$_{tot}$

2.5.8 Heating Plants

In areas with a high population density and/or large industries, environmental problems and economics resulted in the partial substitution of heat generation in private households and commercial buildings by heat production in central heating plants. This option has become even more important because of the need to substitute large quantities of oil in private use. Heating plants serving as peaking or back-up plants in a large district heating system are an ideal complement to coupled production technology. Alternatively, they also allow district heating in regions where large coupled production units are not accessible as a heat source.

Cheap fuel (urban wastes) or alternative heat sources (sewage) can then be used for heat generation, which has a positive impact on the efforts to save costly primary fuels (oil, gas, coal) in the residential and commercial end-use sector. One example of such an alternative heat generation facility has been given in the preceding section, where a coupled production system has been described which extracts its heat energy from a sewage reservoir in a municipal sewage treatment plant. It seems to be natural to use such a system first of all for heat generation (as described by the Swedish project participant). The results of the Swedish assessment of a large electric heat pump system extracting heat from sewage water (temperature

8 - 16 °C) are compared in table 2.28 (Section 2.5.9) with the characteristics of the two conventional heating plants. Table 2.27 shows a direct comparison with the Danish coupled production plant, described in the preceding section. The cost figures of the coupled production system are based on heat output only to facilitate comparison.

TABLE 2.27 - Technical and Economic Key Data of Large Heat Pump Systems

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_H	-	TJ_H	%	%	%	$/kW_H	$/kWH	$/GJH	Yrs
Denmark (Diesel Heat Pump)	11.3	1981	342	80	95	156	279	18	←	15
Sweden (Electric Heat Pump)	10	1982	284	80	90	330	270	8	0.25	15

Assessor of the Swedish Characterization

Leman, G., Energy R&D Commission, Sweden.

Notes:

(1) All energy quantities are based on NCV of fuel.

(2) Uncertainty Ranges

In the Swedish characterization uncertainty ranges were specified for the capacity factors (80 - 88 %; i.e. base load operation), the efficiency (28 - 3.6; median value: 3.3.) and the economic lifetime (10 - 18 yrs; median value: 15 yrs).

2.5.9 Conventional Heating Plants - Characterization Summary

Two types of conventional heating plants have been described by the project participants. These are (country name in brackets):

(1) Oil/Gas-Fired Heating Plant (Belgium)

(2) Coal-Fired Heating Plant (Germany)
With 100 % flue gas desulfurization.

The characterization summary (Table 2.28) also contains data for the Swedish heat pump heating plant to allow a comparison with the conventional systems.

TABLE 2.28 - Technical and Economic Key Data of Heating Plants

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MWh	-	PJh	%	%	%	$/kWh	$/kWh	$/GJh	Yrs
Sweden Heat Pump System	10	1982	0.284	70	90	330	270	8	0.25	15
Belgium Oil/Gas	75	c.a.		15		90	55.5	→	0.74	25
Germany Coal	115	c.a.	32.7	22.8	90.1	77	164.3	21.1	1.25	20

Assessors

Belgium:- Altdorfer, F., Services Programmation de la Politique Scientifique, Rue de la Science 8, B-1040 Brussels

Germany:- Walbeck, M., Martinsen, D., KFA/STE, Postbox 1913, 5170 Jülich

Notes:

(1) All energy quantities are based on NCV of fuels.

(2) Operating and Maintenance Cost

The operating and maintenance cost of the German hard coal heating plant seems too high. The explanation for that will be supplemented.

(3) Uncertainty ranges for data entries were not given in the German and the Belgian characterization.

2.6 References

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3. NUCLEAR POWER PLANTS

3.1 Basics of Nuclear Power

Nuclear power as an energy source can be utilized in two ways, nuclear fission and nuclear fusion. In the nuclear fission process heavy isotopes such as U235, Pu-239, Pu-241, Pu-233 absorb neutrons and split into two dissimilar atoms. In this reaction, between one to five fast neutrons and a quantity of energy are released. The following equation illustrates the process for the fission of uranium 235.

fissile material	+	neutron	$\longrightarrow$	fission products	+	neutrons	+	energy
U235		n	$\longrightarrow$	Ba144 + Kr90	+	2n	+	200 MeV

The energy (about 200 MeV $\approx$ 3.08 x 10^{-11} Ws) predominantly appears in the form of the kinetic energy of the fission fragments which is then converted to heat energy. The neutrons released in the fission process can react with other atoms causing them to fission, and thus create a "chain reaction".

The term "nuclear criticality" is used to describe a sustaining chain reaction, i.e. a reaction which will continue until conditions are altered to make the reaction cease.

In a nuclear reactor heat is generated by a controlled chain reaction. The reactor fuel normally consists of a mixture of fissile and so-called "breeding" material. The "breeding" materials (heavy nuclides such as thorium 232 or uranium 238) also absorb neutrons. They do not split but create short-lived intermediate nuclides, that "decay" to fissile material (sometimes called "secondary" fissile material). The following equation illustrates this process for the conversion of uranium 238 to plutonium 239.

Breeding Material	+ Neutrons	$\longrightarrow$	Intermediate Nuclide	$\longrightarrow$	Intermediate Nuclide	$\longrightarrow$	Secondary Fissile Material	
U238	n	$\longrightarrow$	U239	$\xrightarrow{\beta^-}$	Np239	$\xrightarrow{\beta^-}$	Pu239	

Maintaining of a controlled chain reaction in a nuclear reactor depends upon a number of conditions. Some conditions, concerning the nuclear fuel, are mentioned below.

Firstly, the concentration of fissile material in the nuclear fuel has to be sufficiently high. This allows the neutrons released in the fission process to create a sufficient number of subsequent nuclear fission processes to sustain a chain reaction. The required concentration of fissile material essentially depends on the reactor design.

Secondly, the nuclear fuel must have a defined geometric arrangement in the reactor. In most of the reactor types now in use the nuclear fuel is contained in long slender tubes, which are gathered together into fuel elements. (An exception to this configuration are pebble ball or block fuel elements of the high temperature reactors).

Finally, the temperature in the nuclear fuel must be controlled in such a way that chemical reactions do not occur in the fuel. The heat released in the fission process has to be removed safely. Therefore nuclear fuel in general consists of the heat-resistant uranium, or plutonium oxides. The concept of slender fuel element bundles, with large surface area, allows the heat to be transferred to the cooling fluid with a minimum temperature difference between the element and the fluid.

3.2 Light Water Reactors

3.2.1 General Description

The light water reactor (LWR) gets its name from the fact that ordinary water (term: light water) is used as the cooling fluid and as "moderator" (A moderator slows down the fast neutrons created in the fission process to an energy level where they are more likely to be absorbed by U235, or the secondary fissile material Pu239).

In principle a nuclear power plant is similar in nature to the fossil-fuelled power plants described in chapter 2, except that

the nuclear steam supply system replaces the conventional fuel boiler and the nuclear fuel core replaces the fossil fuel supply. In LWRs the heat energy is basically created by the fissioning of U-235 isotopes. At the same time uranium 238 is converted to the fissile isotope plutonium 239 (compare section 3.1). More than half of this plutonium also undergoes fission in the LWR core, thus contributing significantly to the energy produced in the power plant.

Natural uranium contains only 0.72 per cent fissile uranium-235 and the U-235 concentration in the natural uranium has to be increased to 2-3 per cent before it becomes suitable as LWR fuel (so-called enrichment, see section 3.5). The fuel, in the form of the uranium oxide (UO_2), is contained in long slender tubes bundled together to form fuel elements with spaces between the tubes to allow coolant to flow past them.

Two different types of light water reactors have evolved; the boiling water reactor (BWR) and the pressurized water reactor (PWR). In a BWR water is pumped in a closed cycle from the condenser to the nuclear reactor. In the reactor core heat generated by the fissioning uranium pellets is transferred through the metal cladding to the light water (H_2O) flowing around the fuel element assemblies. The water boils, and a mixture of steam and water flows out of the top of the core into steam separators in the top of the pressure vessel. The separators clean and "dry" the steam before it is piped to the turbine-generators. The turbine exhaust is condensed and returned to the reactor pressure vessel to complete the cycle (see figure 3.1).

Because the energy supplied to the water from the hot fuel is transported directly (as steam) to the turbine, the BWR system is termed a "direct cycle" system. The pressure inside the reactor of a typical BWR is maintained at about 70 bar, with a steam temperature of about 285°C. Neutron-absorbing control rods, operated by hydraulic drives located below the vessel, are used to control the rate of the fission chain reaction.

The primary difference between a pressurized water reactor (PWR)

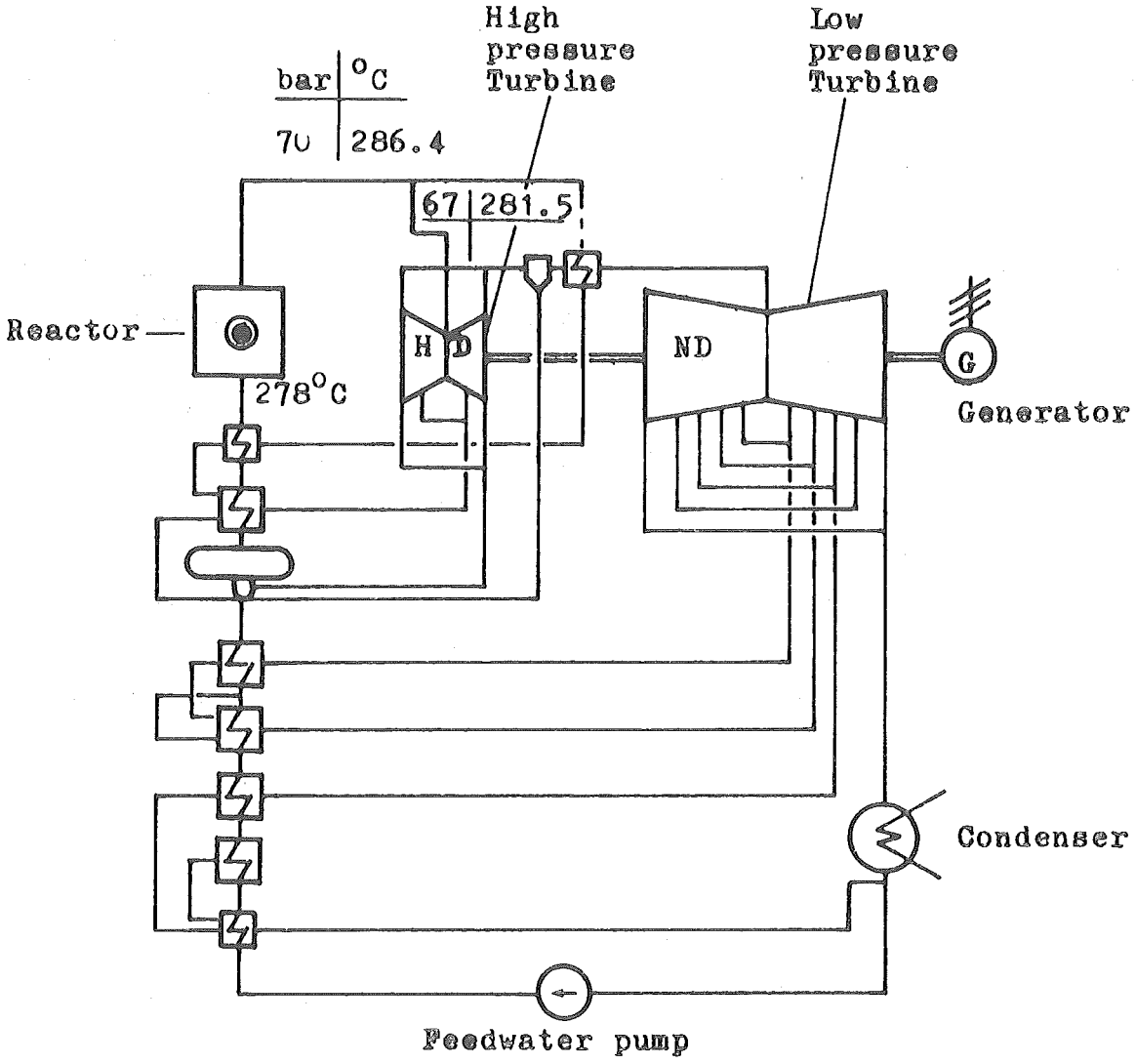

Figure 3.1: Principle of the Boiling Water Reactor (BWR)
(Example of the Krümmel Type, Germany)

and a boiling water reactor (BWR) is that PWRs employ a dual coolant system for transferring energy from the reactor. In the dual coolant system, the primary loop contains water at high pressure that is pumped through the core and the heat exchanger. The secondary loop contains water that is pumped through the steam generators and the resulting steam passes through the turbine (steam cycle). The water in the primary loop is heated to about 317°C by the nuclear core in the pressure vessel, but pressure is sufficiently high (about 155 bar) to prevent boiling. The high pressure water is piped out of the reactor vessel into (usually) two or more "steam generators" that transfer the heat from the primary to the secondary loop, before being pumped back into the reactor. The secondary stream boils, providing steam for the turbine. The steam exhaust from the turbine is then condensed to water and it is pumped back to the steam generator to repeat the cycle. As in BWRs, the nuclear chain reaction is controlled through the use of neutron-absorbing rods. However, in PWRs additional control can be obtained by the dissolving neutron-absorbing chemicals as boron in the primary system coolant; varying the concentration provides the control.

3.2.2 LWR - Characterization Summary

Five characterizations of light water reactors have been provided by the project participants. These are (country name in brackets):

a) Pressurized Water Reactor (Belgium)
Base load power plant

b) Pressurized Water Reactor (Germany)
Base load power plant, equipped with a combined cooling system (evaporative natural draft cooling towers + direct freshwater cooling)

c) Boiling Water Reactor (Japan)
Base load power plant, equipped with a direct freshwater cooling system

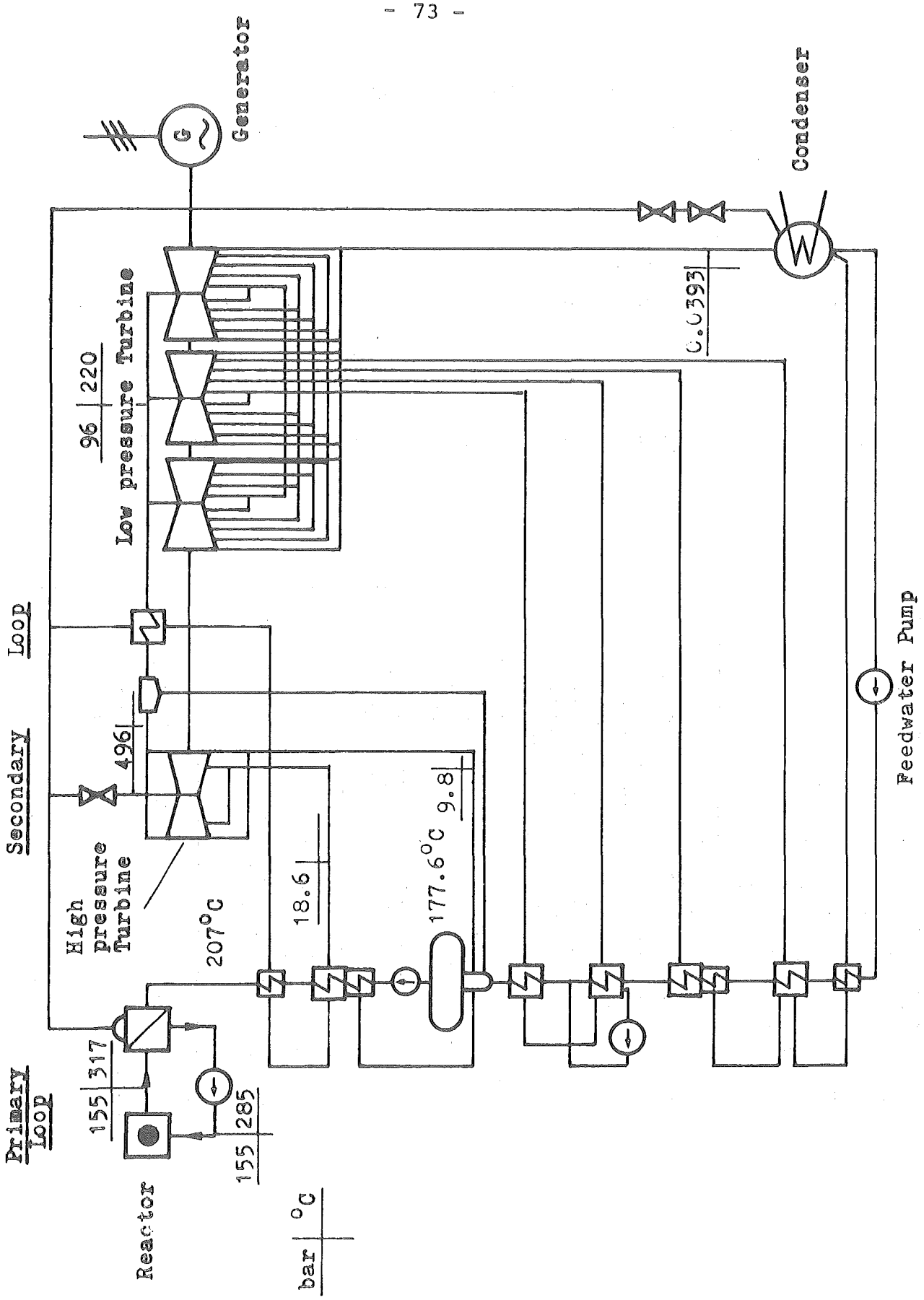

Figure 3.2: Principle of the Pressurized Water Reactor (PWR)
(Example of the Biblis Type, Germany)

d) Boiling Water Reactor (Switzerland)
Base load power plant, equipped with evaporative cooling towers

e) Light Water Reactor (U.S.A.)
Pressurized or boiling water reactor
Base load power plant with evaporative natural draft cooling towers.

TABLE 3.1 - Technical and Economic Key Data of Light Water Reactors

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ_e	%	%	%	$/kW$_e$	$/kW$_e$	$/GJ$_e$	Yrs
PWR (Belgium)	1000	1983	23.3	74	74	32.3	1390	26.1	-	25
PWR (Germany)	1228	c.a.	29	75	75	33	1657	35.2	0.31	20
BWR (Japan)	1000	c.a.	23.7	60	75	33.4	1442	81.6	0.67	16
BWR (Switzerland)	940	1983	22.2	75	75	32	2071	48.2	-	20
LWR (U.S.A.)	1000	c.a.	18.9	60	75	33	1400	29.1	0.41	30

Assessors

Belgium:- Hecq, St., Voie du Roman Pays, 34, B-1348 Louvain-La-Neuve

Germany:- Müller, M., KFA/STE, Postbox 1913, D-5170 Jülich
Japan:- Yasukawa, S., JAERI, Tokai-Mura, Naka-Gun, Ibaraki-Ken
Switzerland:- Kypreos, S., EIR, CH-5303 Würenlingen
U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1)

TABLE 3.2 - Uncertainty Ranges

Country		Median Value	10% Probability of Being		Unit
			Less Than	Greater Than	
Japan	Total Capital Cost	1422	1097	1755	$/kWe
	Fixed O&M Cost	81.6	65.4	97.8	$/kWe
	Variable O&M Cost	0.668	0.529	0.863	$/GJe
U.S.A.	Overall Efficiency	33	32	34	%
	Total Capital Cost	1400	1150	1650	$/kWe

(2) Efficiency

The overall efficiency for the nuclear power plants is defined as the ratio of electric energy output to total heat energy produced in the reactor.

LWRs reach efficiencies around 33 per cent, as compared to 38 to 40 per cent for modern fossil-fuelled plants. The reason for this lower efficiency is that LWR plants operate at a maximum steam temperature of around 315°C while fossil plants operate at 538°C or higher.

(3) Total Capital Cost

The Swiss total capital cost figure gives the investments for the installation of the boiling water reactor in Leibstadt. As this

is the first nuclear power plant in Switzerland, numerous licensing delays occured during the construction of the BWR and a number of plant modifications were made in order to comply with changing safety regulations. The capital cost figure cannot be considered as typical for the installation of further nuclear power plants.

However, it clearly demonstrates the effect that safety system modifications and construction delays by non-standardized licensing proceedings have on the economics of nuclear power plants.

The cost figures estimated by the other assessors give cost expectations for light water reactors under the assumption of standardized licensing proceedings so eliminating excessive construction delays. The difference in the countries' estimates reflect the different safety standards for nuclear power plants, so far as they are prescribed in the individual countries as a result of licensing proceedings. However, in most of the countries standard licensing procedures do not yet exist. For this reason all cost estimates should be regarded as having considerably uncertainty.

(4) Operating and Maintenance Cost

In order to allow a direct comparison, table 3.3 summarizes the total O&M cost of the LWR power plants, expressed as cost per energy unit produced. The total O&M costs of the LWR power plants, expressed in cost per unit of energy produced, are summarized in Table 3.3. The calculation of these cost has been made assuming that the power plants operate at the capacity factor specified in the summary table.

TABLE 3.3 - Total Operating and Maintenance Cost of Light Water Reactors

Country	Reactor Type	Total O&M Cost ($/GJe)
Belgium	PWR	1.12
Germany	PWR	1.80
Japan	BWR	4.98
Switzerland	BWR	2.04
U.S.A.	PWR/BWR	1.95

The Japanese estimate includes costs for administration, personnel, infrastructure, buildings, etc. (overheads) under the O&M cost.

3.3 Advanced Converter Reactors

3.3.1 Gas-Cooled High Temperature Reactor

The high temperature reactor (HTR) is a thermal reactor, moderated by graphite and cooled by helium gas. The nuclear fuel of the HTR generally consists of uranium with thorium as "breeding" material. The exact isotopic composition of the fuel, however, basically depends upon the fuel cycle chosen. Possible HTR fuel cycle concepts are summarized below, a distinction has been made between open and closed cycles.

a) Open Fuel Cycles

- LO : Low Enriched Open Cycle,
  Pure uranium cycle (U-238, U-235)
  with 8.5% enrichment

- MO : Medium Enriched Open Cycle,
  Uranium-Thorium-Mixed Oxide Cycle
  The uranium is enriched to 19.8%

- HO : High Enriched Open Cycle,
  Uranium-Thorium-Mixed Oxide Cycle
  The uranium is enriched to 93% U-235

b) Closed Fuel Cycle

- MR : Medium Enriched, Recycling
  Same fuel composition as in the MO case with, however, reprocessing of the spent fuel

- HRS : High Enriched, Recycling: Separate Elements
  U-Th-Cycle with uranium (U-233 + U-235) recycling in thorium-free fuel elements

- HRM : High Enriched, Recycling in Mixed Oxid Element
  U-Th-cycle with uranium (U-233 + U-235) recycling in U-Th-mixed oxide fuel elements

- PB-NB : Pre-Breeder-Near-Breeder System

- PB : U-Th-cycle with 93 % enriched uranium, separate feed-breed-fuel elements. The major part of the U-233 "bred" from thorium is charged to the NB reactor

- NB : Breed elements and U-Th-mixed oxide fuel elements containing recycled U-233

In all concepts put forward to date, the HTR fuel is contained in particles of 1 mm in size and surrounded by a multi-layer carbon-coating. These so-called "coated particles" can resist an inner pressure of 1000 bar and represent an extremely effective barrier against the release of fission products from the fuel. The small particles are mixed with graphite powder and pressed into fuel elements. They can have the form of either fuel balls (German concept) or fuel rods (American concept). In the German concept, the outer 5-10 mm of the 6 cm fuel balls are kept free of fuel in order to guarantee additional protection. In the American concept, the pressed fuel rods are contained in holes in large graphite blocks (26 cm across with a height of 80 cm), which have additional holes for the coolant.

As mentioned above, in the high temperature reactor the noble gas helium is used as a coolant. Helium is chemically inactive and has no effect on the neutron balance in the core. By careful design, coolant outlet temperatures in the region of 700 to 1000°C can be achieved. Consequently, steam can be generated in a secondary loop under conditions which are comparable to those of modern conventional steam power plants. Because of the good thermal conductivity of graphite and the low power density in the HTR core, the maximum fuel temperature only reach 1100 - 1500°C.

The heat generated by nuclear fission in the HTR core is transferred by the cooling gas either into a secondary steam turbine cycle (see figure 3.3) or used directly in a gas turbine (see figure 3.4).

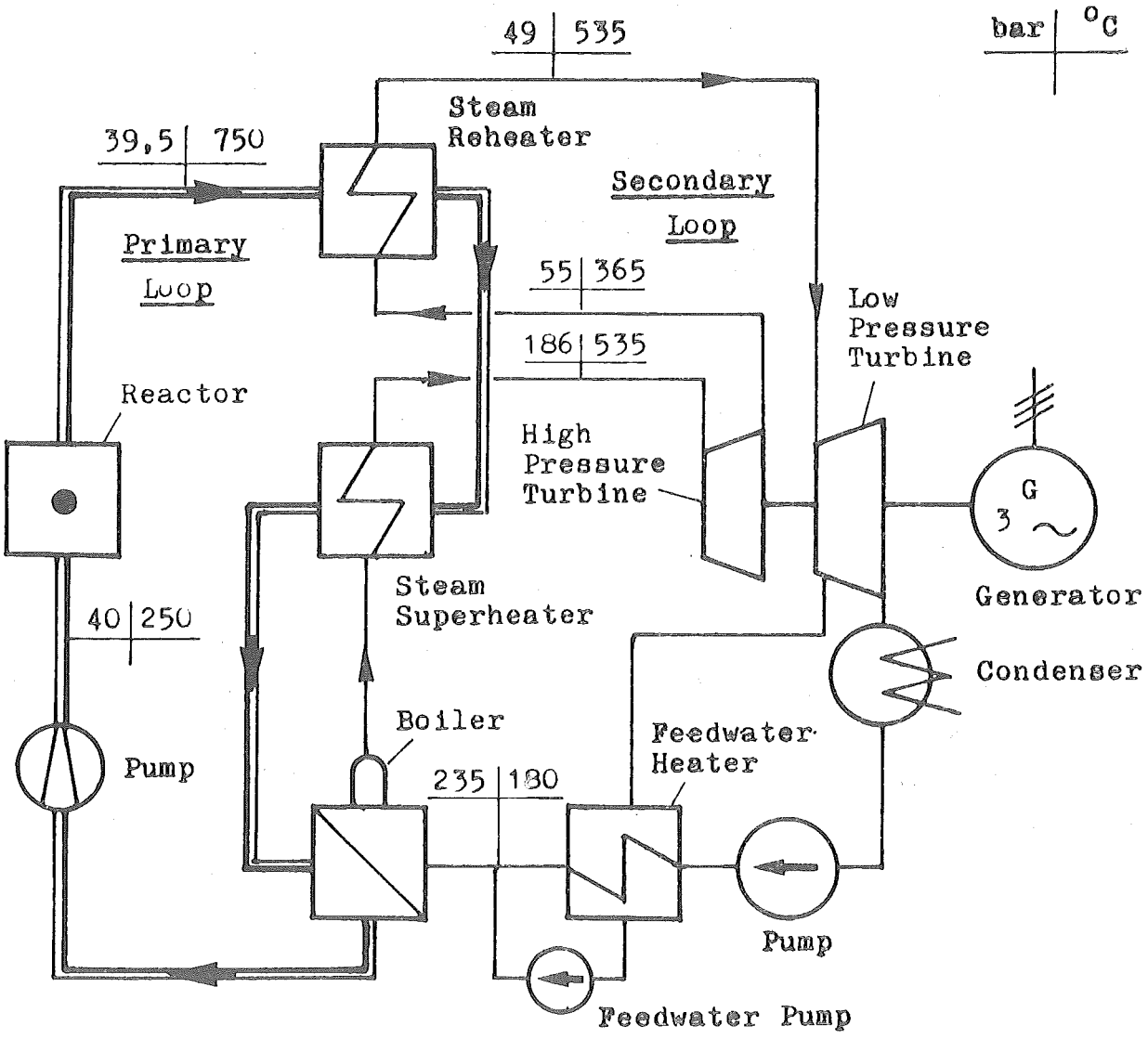

Figure 3.3: HTR-Steam Turbine Concept

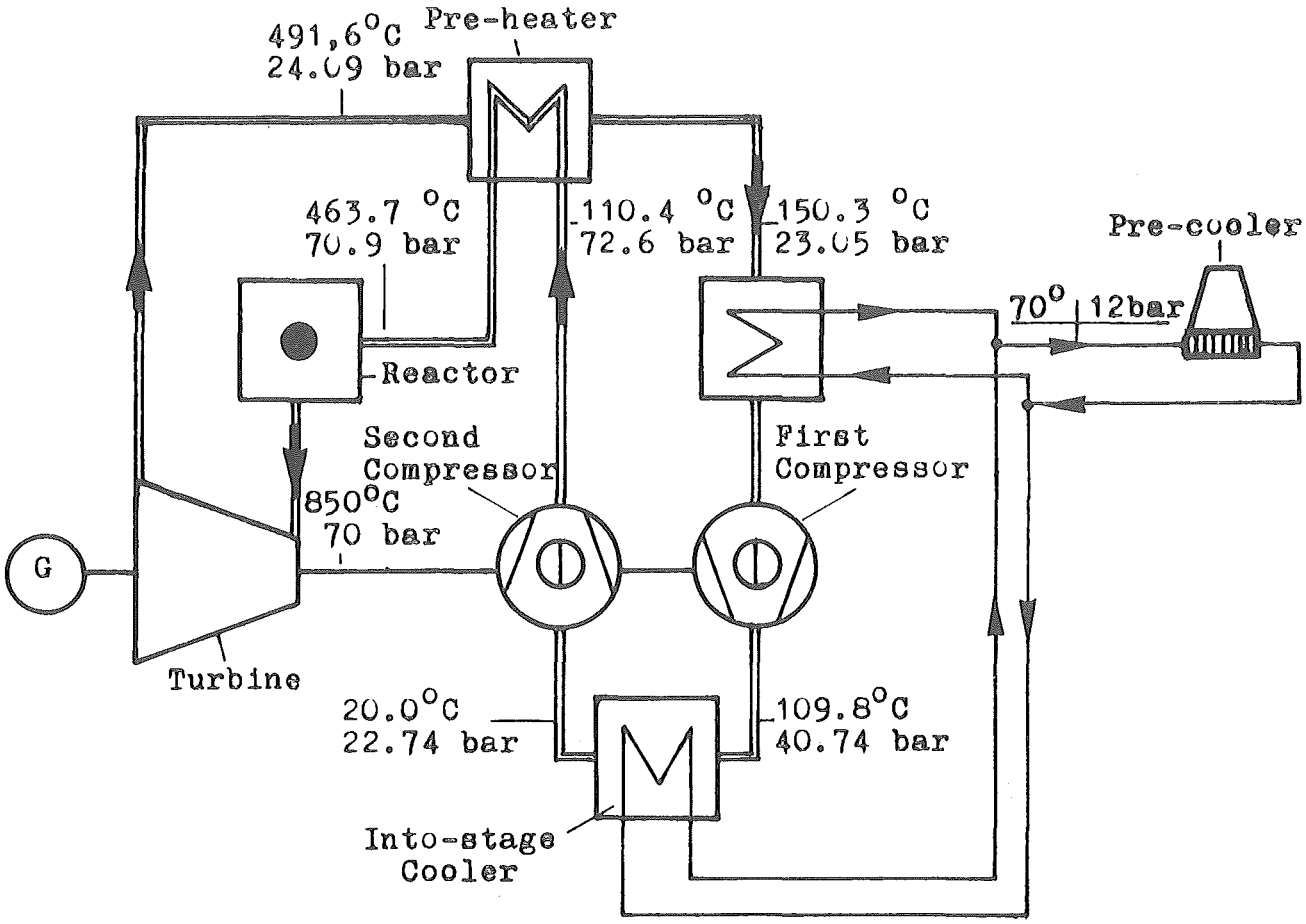

Figure 3.4: HTR-Helium Turbine Concept

Besides the HTR power plants described above, a high temperature reactor for process heat production (VHTR) has also been considered. The heat generated in the VHTR core is used to heat the coolant to more than 900°C and is at a considerable pressure (in the Japanese concept: 40 atm). Thus, it is suitable as a substitute for conventionally generated heat for high temperature industrial processes, for example, coal gasification and liquefaction (compare also section 4.5)

3.3.2 Characterization Summary of Advanced Converter Reactors

In the following, technical and economic data for high temperature reactors are summarized and compared with the Japanese advanced thermal reactor (ATR) system and the British advanced gas cooled reactor (AGR). In detail the following systems have been described (country name in brackets):

(1) High Temperature Reactor (HTR) (Germany)
Base load power plant. Pebble bed reactor.
High temperature helium turbine concept for electricity generation. HRM-fuel cycle. Equipped with a dry cooling system.

(2) Very High Temperature Reactor (VHTR) (Japan)
The system generates high temperature process heat (40 atm, 930°C). LO-fuel cycle (enrichment 6% in the initial core, 8% in the equilibrium cores).

(3) Advanced Thermal Reactor (ATR) (Japan)
Base load power plant. Heavy water moderated reactor (carandria tube type) with boiling light water coolant.
Natural uranium - plutonium-fuel cycle.

(4) AGR (United Kingdom)
Base load power plant. Advanced gas cooled reactor
A high temperature, carbon dioxide cooled reactor with steam generators providing steam for a conventional steam cycle.

(5) High Temperature Gas Reactor (HTGR) Power Plant (U.S.A.)
Base load power plant, equipped with natural draft evaporative cooling towers. HTR-steam cycle concept.
(Information about the fuel cycle has not been provided)

TABLE 3.4 - Technical and Economic Key Data of Advanced Converter Reactors

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW	-	PJ	%	%	%	$/kW	$/kW	$/Gj	yrs
HTR (Germany)	1228	2000	29	75	75	41.4	2010	41.7	0.31	20
VHTR* (Japan)	1000	2005	25.2	80	80	93	960	28.1	0.55	16
ATR (Japan)	600	1991		70		31	1466	79.9	-	16
AGR (United Kingdom)	1000	1985	22.1	70	70	32	2645	21	0.28	25
HTGR (U.S.A.)	1000	1995	18.9	60	75	34	1500	30.95	0.31	30

*This system generates process heat only

Assessors

Germany:- Müller, M., KFA/STE, Postbox 1913, D-5170 Jülich
Japan (VHTR):- Sakae, T., JAERI, Tokai-Mura, Naka-Gun, Ibaraki-Ken
Japan (ATR):- Nakamura, T., PNC, Tokyo
United Kingdom:- Ward, A.V., ETSU, Harwell
U.S.A. (HTR):- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) TABLE 3.5 - Uncertainty Ranges of Data Entries

Technology	Item	Median Value	10% Probability of Being		Unit
			Less Than	Greater Than	
VHTR (Japan)	Total Capital Cost	960	913	1057	$/kW$_h$
	Fixed O&M Cost	28.1	26.7	31.0	$/kW$_h$
	Variable O&M Cost	0.548	0.527	0.614	$/GJ$_h$
AGR (U.K.)	First Commercial Service Year	1985	1983	1986	-
	Total Capital Cost	2645	2200	3170	$/kWe
	Fixed O&M Cost	21	15	26	$/kWe
HTGR (U.S.A.)	Overall Efficiency	34	32	36	%
	Total Capital Cost	1500	1250	1700	$/kWe

Other uncertainty ranges were not specified

(2) Efficiencies

With the helium turbine HTR concept, considerably higher efficiencies can be achieved than with the HTR steam cycle system. Studies for the German THTR 300 project (steam cycle HTR power plant with a dry cooling system) indicate a maximum thermal efficiency of 38.3 % for the steam cycle system. For the helium gas turbine concept an 44.5 % efficiency seems within reach, if the turbine inlet temperature of the hot helium gases is increased to 950°C.

(3) Total Capital Cost

- In the German estimate, a factor of 1.2 has been assumed to calculate the HTR investments from the total capital cost of a conventional light water reactor (compare table 3.1).

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- A direct comparison of the entries is not meaningful in any case as the described systems are too different technically.

- The Japanese VHTR produces process heat. All specific cost entries relate to heat production.

(4) Operating and Maintenance Cost

TABLE 3.6 - Total Operating and Maintenance Cost

Country	Reactor Type	Total O&M Cost (¢/GJ)
Germany	HTR	2.07
Japan	VHTR	1.66*
Japan	ATR	3.62
United Kingdom	AGR	1.23
U.S.A.	HTGR	1.95

*This entry is related to heat output

3.4 Fast Breeder Reactors

3.4.1 The Liquid Metal Fast Breeder Technology

The fast breeder reactor is generally regarded as the successor to the light water reactor. Its technological concept is completely different from all reactor types discussed in the previous sections, especially with respect to the neutron spectrum (energy distribution of the neutrons) and core construction. Instead of slow (termed: thermal) neutrons, fast neutrons maintain the fission process in the reactor core: i.e. a moderator is no longer required to slow down the neutrons created in the chain reaction. Therefore the reactor core of a fast breeder can be built more compactly than with other reactor types.

Besides energy production, the fast breeder produces fissile material by a so-called breeding process, by converting the thermally non-fissile U-238 by neutron capture into fissile plutonium Pu-239 and Pu-241.

Because of the compact core construction, the power density in a fast breeder core is higher (by a factor of around 5) than that of a LWR. This requires a coolant with particularly good heat transfer properties.

One material which meets these requirements is liquid sodium (Na). The fast breeder reactor, therefore, is very often referred to as liquid metal cooled, fast breeder (LMFBR). However, sodium is not chemically inactive. It reacts exothermically with air and water. For this reason a number of special safety aspects have to be considered; for example, an additional circuit, also with sodium (Na) as coolant, is usually installed between the primary (core) circuit and steam circuit (see figure 3.5).

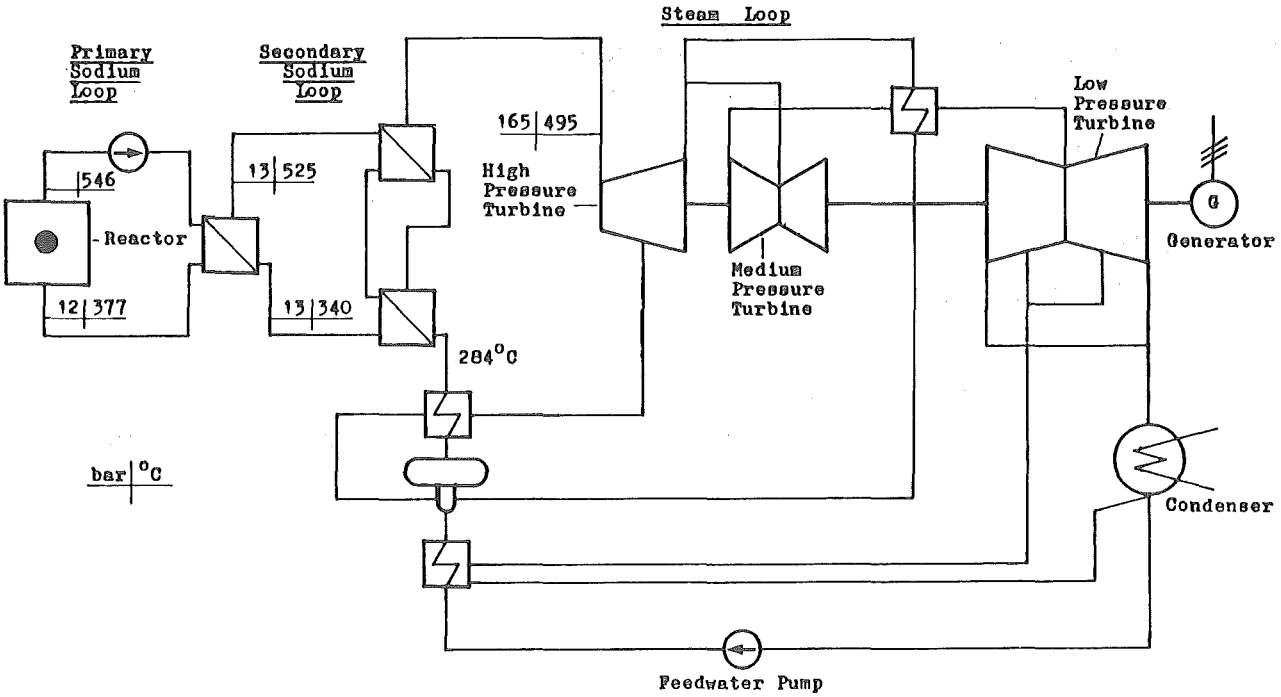

Figure 3.5: Block Diagram of a LMFBR (SNR-300, Kalkar, Germany)

The major advantage of an LMFBR comes from its ability to "breed" fissile material from the non-fissile U-238. While the light water reactor requires enriched

uranium and exploits only up to 10% of the invested fuel, the breeder can initially be fuelled with plutonium discharged from light water reactors, together with depleted uranium from the enrichment facility, as breeding material. With a breeding rate higher than one, the fast breeder reactor then creates more fissile material from the depleted uranium than it requires for its subsequent replacement loadings. The breeder thus has the advantage of using uranium reserves much more effectively than the LWR.

3.4.2 Characterization Summary

The project participants provided 4 characterizations of fast breeder reactors for this report. They are (country names in brackets):

(1) Liquid Metal Fast Breeder (Belgium)
Super Phénix reactor (France).
Base load power plant.

(2) Liquid Metal Fast Breeder (Germany)
Super Phénix concept. Base load power plant, equipped with evaporative cooling towers.

(3) Liquid Metal Fast Breeder (Japan)
Base load power plant.

(4) Liquid Metal Fast Breeder (U.S.A.)
Base load power plant, equipped with natural draft evaporative cooling towers.

TABLE 3.7 - Technical and Economic Key Data of Fast Breeder Reactors

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	PJ	%	%	%	$/kW_e$	$/kW_e$	$/kW_e$	Yrs
Belgium	1000	1984	23.3	70	74	39	1807	34.4	-	25
Germany	1228	2000	29	75	75	38	2458	49.9	0.31	20
Japan	1000	2000		80		41	1849	71.5	-	16
U.S.A.	1000	2002	18.9	60	75	34	1750	32.36	0.43	30

Assessors

Belgium:- Hecq, St., Voie du Roman Pays, 34, B-1348 Louvain-La-Neuve

Germany:- Müller, M., KFA/STE, Postbox 1913, D-5170 Jülich

Japan:- Otake, I., PNC, Tokyo

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) TABLE 3.8 - Uncertainty Ranges of Data Entries

Country	Item	Median Value	10% Probability of Being		Unit
			Less Than	Greater Than	
Belgium	Total Capital Cost	1807	1529	2085	$/kWe
	Fixed O&M Cost	34.36	29.12	39.73	$/kWe
Japan	Capacity Factor	80	70	80	%
U.S.A.	Overall Efficiency	34	32	36	%
	Total Capital Cost	1750	1500	2100	$/kWe

(2) The total operating and maintenance cost of the breeder reactors are summarized in the table 3.9. They are expressed as variable O&M cost (unit: $/GJe). The conversion from fixed and variable O&M cost to total O&M cost has been made under the assumption that the reactors operate at the capacity factor given in the summary table.

TABLE 3.9 - Total Operating and Maintenance Cost

Country	Total O&M Cost ($/GJe)
Belgium	1.56
Germany	2.42
Japan	2.83
U.S.A.	2.14

3.5 Nuclear Fuel Cycle

3.5.1 The Uranium Resource

Uranium is an element and it occurs in nature as a compound. About 95 per cent of the uranium is in the form of uranium oxide (uraninite or pitchblende). Most of the remaining five per cent occurs as uranium hydrons silicate compounds (known as coffinite) or potassium uranium vanadate (known as curnotite). Uranium consists of three naturally occuring isotopes in the following proportions: 99.29 per cent U-238, 0.71 per cent U-235 and a trace of U-234.

Although uranium occurs more often on earth (2.7 ppm[1]) than, for example, silver (0.07 ppm) or gold (0.004 ppm), deposits with an uranium concentration in the range of parts per hundred are very scarce. This results from the high chemical reactivity of uranium: frequent solution and precipitation during the course of earth's history has led to a (nearly) world wide dispersion of the original uranium concentrations.

About 180 minerals consisting mainly of uranium exist on earth. Among the multitude of deposits, however, three major groups can be distinguished:

- petrified rivers
- veins
- ancient conglomerates.

Ancient conglomerates are old stream channel deposits that were formed more than one-half million years ago. The difference between petrified rivers and veins is that the host sandstone containing the uranium lies horizontally in the first and vertically in the second.

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[1] ppm = parts per million

.5.2 Exploration

xploration for uranium divides into three principle phases:

- preliminary investigations
- detailed geological studies
- detailed physical exploration

The objective of the preliminary investigation is to identify uranium host rocks, usually sandstone, in a larger region. For this purpose, many data are obtained from available reports and aerial photographs and reviewed. The detailed geological study then includes all or some of the following activities: surface mapping, sampling, preparing subsurface maps and performing geochemical, geophysical and aerial surveys. Although these activities generally parallel those used in prospecting for other minerals, some uranium prospecting techniques rely on the ore's radioactivity to aid in its location. The uranium in the ore emits gamma rays which can be detected, e.g. by Geiger-Müller tubes (Geiger counters) or scintillometers. This so-called radiometric prospecting is most effective in locating uranium deposits that are older and close to the surface. Where the deposit is recent or where there is a thick overburden, however, it is less reliable. Additionally, such prospecting sometimes picks up radiation from thorium and potassium rather than uranium. Therefore, deposits found by radiometric prospecting must be confirmed by other geophysical or geochemical techniques. Another prospecting method involves monitoring for radon gas. Radon gas is a radioactive gas naturally produced from uranium. It can be identified either by scintillometers or by sensitive film.

The final phase of exploration involves drilling into the suspected ore deposit. It is usually done with rotary or pneumatic percussion equipment. Drilling allows two types of final assessments: scintillometer measurements at various depths in the bore hole and geochemical analyses of the material brought to the surface. Data from these two measures are correlated to determine uranium concentrations at various depths (3.1).

3.5.3 From Uranium Ore to Yellow Cake

The first production step that the uranium undergoes on its way to nuclear fuel is the mining of the ore and the subsequent conversion to a compound rich in uranium oxide termed "yellow cake" (uranium content of about 70 per cent). As the ore in the deposit contains only 0.05 to 0.2 per cent uranium, considerable amounts of ore have to be processed. For this reason mining and yellow cake processing takes place at the same location as a transportation of the ore to a central yellow cake plant would be too costly.

Uranium ores are mined in open pit mines as well as in underground mines. The decision as to which mining technique is chosen depends upon depth, size, assay and host formation of the ore body.

The subsequent yellow cake production (also termed "milling") consists of the following process sub-steps:

1. Crushing and grinding: The basic purpose of this step is to reduce the particle size so that reaction can be accomplished more rapidly.

2. Leaching: After the physical grinding, the uranium minerals are dissolved (or "leached") from the host rock, the type of chemical used in this process is determined by the composition of the uranium in the ore and by the other minerals present. The two primary leaching agents are sulphuric acid and either sodium carbonate or sodium bicarbonate. Most of the yellow cake is produced using the cheaper process with sulphuric acid as leaching agent.

3. Washing (Separation): Regardless of the leaching method, the leached solution is then "washed" with water to remove the sand and slime.

4. Purification: Uranium is separated from all the other leached minerals by passing the washed solution through a "purification" step. The purification process selectively removes the uranium from the water solution and leaves the unwanted metals in the solution.

5. Precipitation: The purified product then enters a precipitation stage where ammonia, air, and heat are used to produce an insoluble form of uranium.

6. Separation: The solution containing suspended uranium particles passes to a thickener and the resulting product from the thickener, yellow cake, is washed and dried.

The final product, yellow cake, is (as already mentioned) a uranate or a compound of different uranates with uranium concentrations between 70 and 75 per cent. In order to facilitate a comparison of the different products with regard to their uranium concentration, the stable oxide of uranium, the U_3O_8, has been chosen as a standard. Note, however, that yellow cake is not the same as U_3O_8. Yellow cake is a compound that meets certain technical purity specifications in order to be suited for the subsequent fluorination process.

The following table summarizes technical and economic data of a uranium mill, which produces yellow cake with a concentration of 75 per cent U_3O_8 from uranium ore containing 0.2 per cent U_3O_8. The data have been provided by the American project participant.

TABLE 3.10 - Technical and Economic Data of a Uranium Mill

	Output Capacity (Yellow Cake)	Annual Ore Throughput	Capacity Factor	Maximum Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	t/yr	t/yr	%	%	$/(t/yr)	$/(t/yr)	$/t	yrs
	885	299000	90	90	16200	1150	8110	30

Assessor

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973.

3.5.4 The Fluorination Process

In the fluorination process the uranium in the yellow cake is converted to uranium hexafluoride (UF_6). The purpose of this process step is to produce a compound for the subsequent enrichment step that

- is gaseous at as low a temperature as possible, as all enrichment techniques are based on a gaseous process medium,
- does not contain other compounds whose molecular weight is close to that of the uranium isotope compounds, as this would interfere with the uranium enrichment,
- is chemically and thermally stable.

Uranium hexafluoride largely fulfills these conditions. It sublimes under normal pressure already at 56.5°C, solely contains the element

fluorine, which has only one isotope (F19) and is chemically and is thermally stable, under normal processing conditions.

At present two processes of producing UF_6 are being used: the dry hydrofluor process and the wet solvent extraction-fluorination process. Common steps of the two processes are the hydrofluorination (UO_2 reacts with HF to produce uranium tetrafluoride UF_4) and the fluorination (UF_4 reacts with fluorine gas (F_2) to produce UF_6). In essence, the processes differ at the point where impurities are removed. The dry method produces the gas, then removes the impurities by distillation. The wet technique removes impurities from the yellow cake before the gas is made. Figures 3.6 and 3.7 show the respective processes.

For the Energy Technology Systems Analysis Project two characterizations of the wet solvent extraction-fluorination process (also termed refining-fluorination process) have been provided. Table 3.11 summarizes the substantial technical and economic data of the systems and compares them with data of a dry hydrofluor process.

TABLE 3.11 - Technical and Economic Data of the Fluorination Process

Country	Technology	Design Capacity	First Commercial Service Year	Yellow Cake Input per year	Capacity Factor	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
	Unit	tU/yr	-	tU	%	$/(tU/yr)	$/(tU/yr)	$/tU	years
Japan	Refining-Fluorination Process	3582	1997	2952	82	15930	1870	2870	10
U.S.A.		9000	-	7240	80	12900	1420	2870	15
Japan	Hydroflour Process	3000	-	-	70	12060	1050	700	15

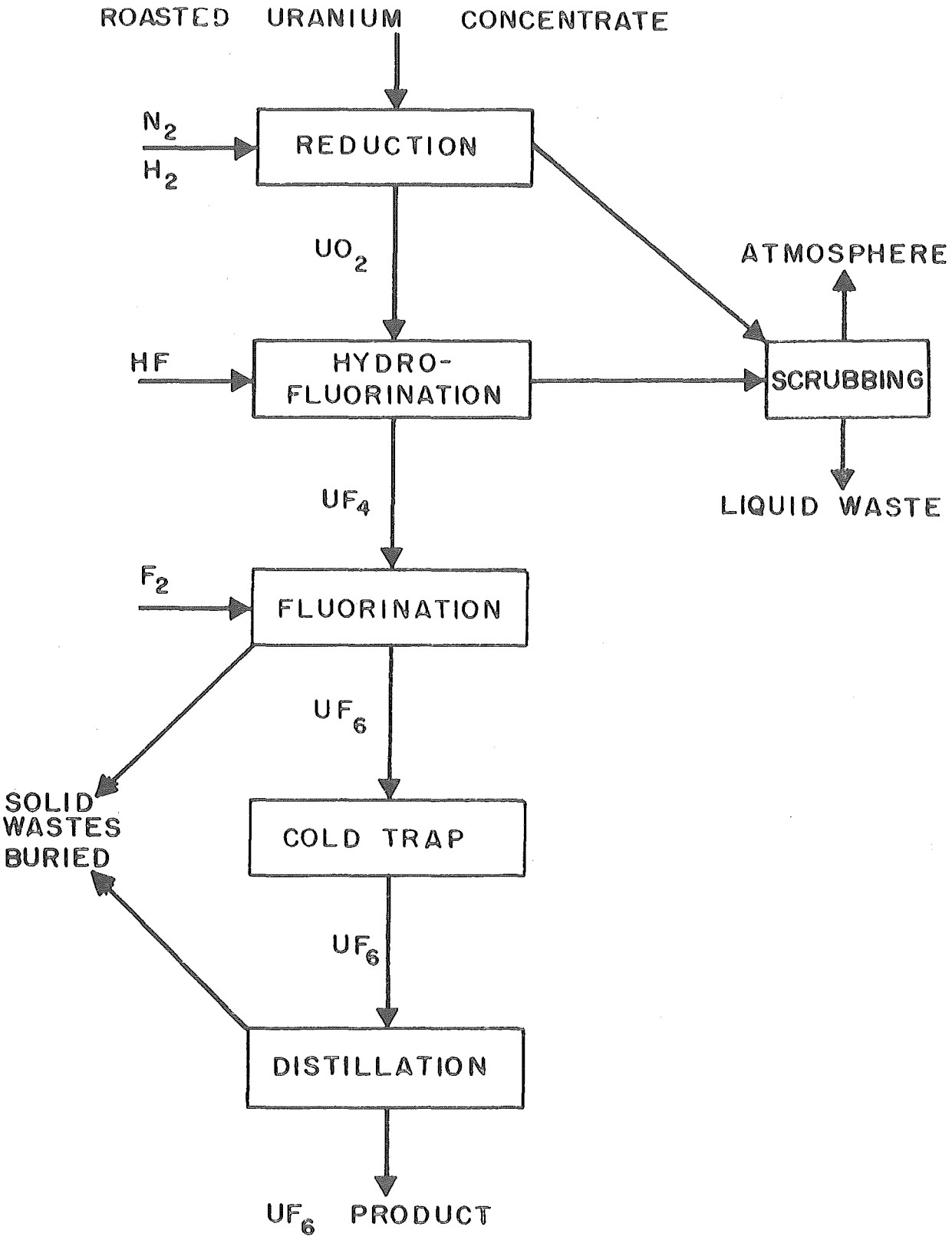


Figure 3.6: Dry Hydrofluor Process

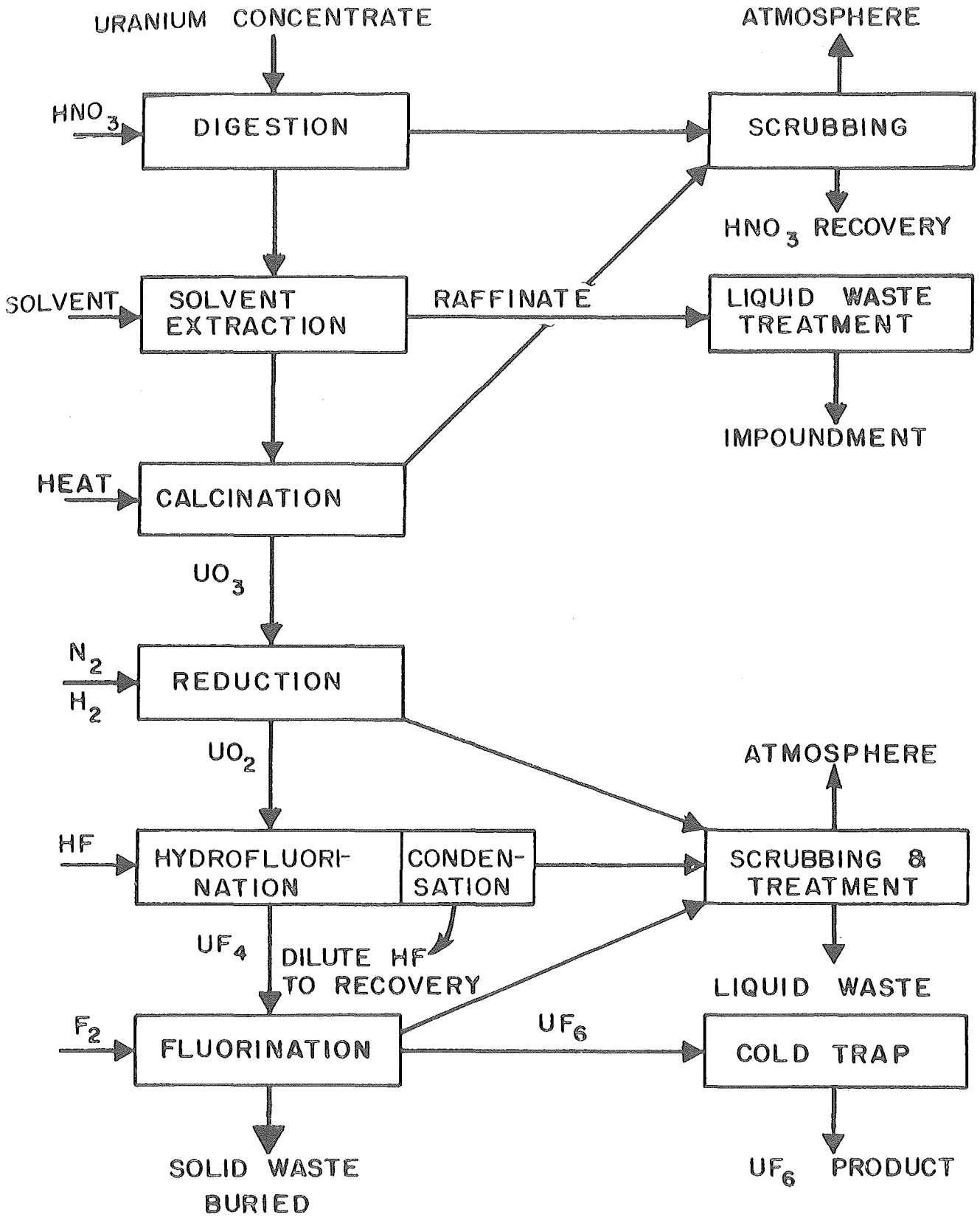


Figure 3.7: Wet Solvent-Extraction Fluorination Process

Assessors

Japan:- Wakabayashi, S., PNC, Tokyo, Japan
U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) Uncertainty ranges were not specified except in the Japanese characterization where for the total capital cost 23650 $/(tU/yr)) has been given as another possible estimate of the required investments.

(2) Design Capacity

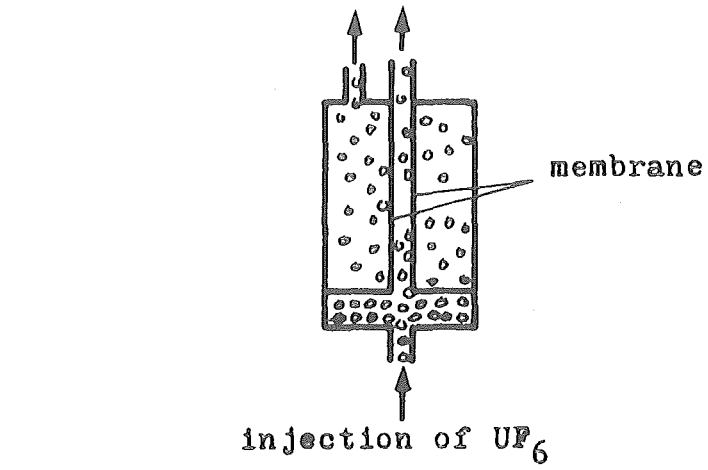
In the Japanese characterization the design capacity was expressed as input capacity (3600 tU/yr yellow cake). In the summary table, however, the capacity is defined as output related value! Therefore, the UF_6 output of the refining fluorination plant (3582 th/yr, which corresponds to 3600 tU/yr yellow cake input) has been taken as design capacity.

3.5.5. Basics of Uranium Enrichment

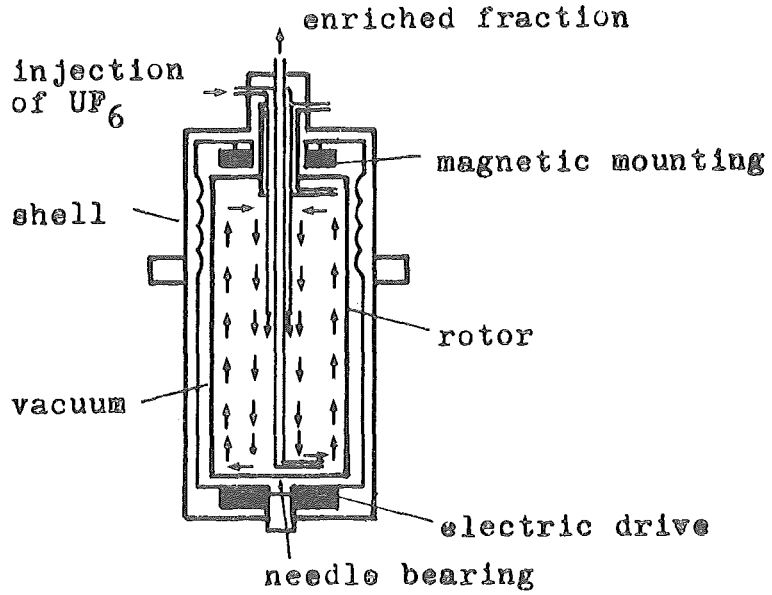
Uranium hexafluoride, the end product of the fluorination process, is a mixture of U-238 and U-235 F_6. The concentration of the U-235 isotope in the UF_6 compound is 0.71 wt % (as in natural uranium). The purpose of the enrichment process is to partially separate the two chemically similar gases, and produce uranium hexafluoride with a higher concentration of the fissile U-235 than is contained in natural uranium. As already mentioned, both compounds U-235 F_6 and U-238 F_6 react the same chemically, they do, however, differ in atomic weight. Therefore, physical methods making use of the weight difference are currently applied in enrichment technology.

At present, three uranium enrichment processes are operational. The gaseous diffusion process, the ultracentrifuge process and the nozzle process. Other techniques, like laser enrichment, uranium plasma separation or chemical exchange reaction processes are still under development. Description of the gaseous diffusion and ultracentrifuge processes are given below together with their characterisations.

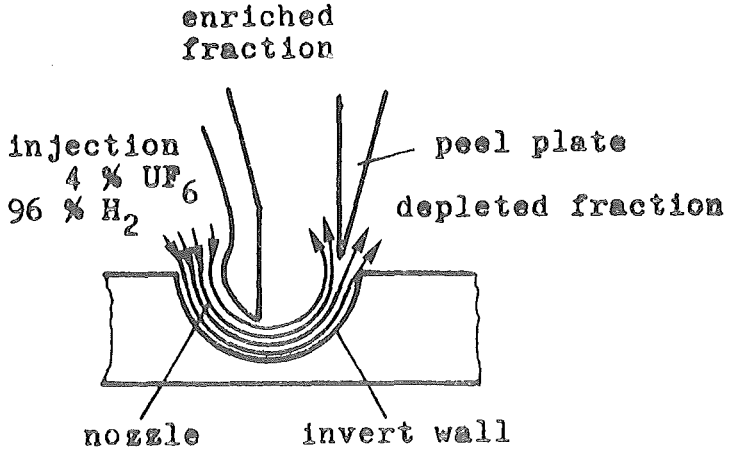
Diffusion Process



Centrifuge Process



Nozzle Process



3.5.6 The Gaseous Diffusion Process

The gaseous diffusion process (Figure 3.8(a)) is based on the physical principle that gaseous molecules differing in weight move with different velocities (Brownian movement). If a gaseous stream now flows by a porous wall or membrane, the lighter molecules pass through the membrane at a higher rate than the heavier ones.

The gas flows through a system of pipes with porous sides which function as diffusion membranes. Porosity, side surfaces, pressure differences, etc. are designed in such a way that about half of the stream fed to a stage diffuses through the membranes and, as enriched product gas, can be pumped to the next diffusion stage.

Uranium hexafluoride consists of U-238 F_6 and U-235 F_6 and there is a weight difference between these two molecules. A high pressure feed stream of UF_6 passing over a membrane is made to separate into two outgoing streams of UF_6, one which has diffused through the membrane and contains a higher percentage of the lighter U-235 F_6 than the input feed stream. The other which has passed over the membrane has been depleted of U-235 F_6.

However, the weight difference between the U-235 F_6 and the U-238 F_6 molecules is only marginal. Therefore, the theoretical separation factor obtainable by diffusion is very small. A 3 % enrichment of natural uranium requires approximately 1200 separation stages which are connected in series to form a separation cascade. The UF_6 gaseous stream is pumped from stage to stage by axial-flow compressors. After compression the gas passes through a heat exchanger to be cooled down.

3.5.7 The Ultracentrifuge Process

The most obvious process for separating components of different weights is the centrifuge process. Isotope separation by centrifuging was demonstrated fifty years ago.

A gas centrifuge of modern technology (figure 3.8(b)) consists of an electrically-driven motor, the whole centrifuge rests on a needle bearing and it is held upright by an upper magnetic bearing. Gaseous uranium hexafluoride is injected into the rotor close by the rotor axis. The centrifugal force generated by rotation causes the heavier U-238 F_6 molecules to drift outwards at a higher rate than the lighter U-235 F_6 molecules. Unequal flow resistances at the rotor ends combined with a temperature gradient along the rotor causes an axial movement of the gas stream so that it flows downwards close to the rotor axis and flows upwards at the rotor walls. This "counter-current" action amplifies the isotopic separation in the centrifuge with the light U-235 components building up at the rotor bottom, while the heavier U-238 concentrates at the rotor top. The enriched product stream is tapped from the rotor bottom and the depleted waste stream is tapped from the top.

The operation of the centrifuge produces a pressure gradient between gas inlet and gas outlets which is high enough to operate a centrifuge cascade without additional pumps and compressors. The "separative work" of a centrifuge increases by the fourth power of the rotor periphal velocity and is approximately proportional to the rotor length. For this reason the centrifuge rotors are designed as long cylindrical bodies made from materials with a high strength to weight ratio (e.g. high strength aluminium, fibre-reinforced materials, maraging steels). The rotors are operated in a vacuum in order to minimize friction losses.

In the following table are the summarized technical and economical characteristics of three centrifuge enrichment plants. These are (country name in brackets):

(1) Centrifuge Enrichment Plant (Japan)
Proposed system for the production of low-level,enriched uranium hexafluoride.

(2) Centrifuge Enrichment Plant (U.S.A)
Proposed system for the production of low-level,enriched uranium hexafluoride

(3) Centrifuge Enrichment Plant (Netherlands)
The Dutch characterization describes a 1000 t SWU/yr commercial plant which is to be built in Almelo (Netherlands).. A similar plant is at present under construction at Capenhurst (U.K.) and a third one will be built in Gronau (West Germany). The enrichment plants are designed and constructed by CENTEC and will be operated by URENCO which already operates two 200 t SWU/yr demonstration plants located at Almelo and Capenhurst.
German, Dutch and British companies have a share of one third each in both CENTEC and URENCO. They intend to install and to operate an enrichment capacity totalling 2500 t SWU/yr by 1985 and 7500 t SWU/yr by 1990 in the three countries.

TABLE 3.12 - Technical and Economic Data of the Centrifuge Enrichment Process

	First Commercial Service Year	Capacity	Product Enrichment	Tail Enrichment	Inputs			Output		Capacity Factor	Max. Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
					UF_6	Electricity	Fuel Oil	Enriched UF_6	Tail						
Unit		tSWU /yr	%	%	tU	PJ	PJ	tU	tU	%	%	$\frac{\$}{tSWU/yr}$	$\frac{\$}{tSWU/yr}$	$\frac{\$}{tSWU}$	yrs
Japan[1]		3300	3	0.2	4200	2.02	0.824	761	3420	90	90	623 000	16 000	17 000	13.3
U.S.A.	1992	6000	3	0.2	7640	3.67	1.5	1380	6220	90	90	519 000	13 300	17 000	15
Netherlands	1985	1000	2.8	0.25	1610	0.58	-	290	1320	97	97	625 000	24 990		15

Assessor

Japan : - Yasukawa, S., JAERI, Tokyo, Japan
U.S.A.: - Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973
Netherlands: - Kram, T., ESC, Petten

Notes

(1) Units

tSWU - a tonne separative work unit (Note that the term SWU implies a kilogram separative work unit)

The specific separative work of an enrichment plant, i.e. the separative work required for the production of 1 kg of enriched uranium, is calculated according to the following formula:

$$SWU = V(x_E) + \frac{T}{E} V(x_T) - \frac{P}{E} V(x_P)$$

$$= V(x_E) - V(x_T) + c\,(V(x_T) - V(x_P))$$

with $$V(x) = (1-2x) \ln \frac{1-x}{x}$$

$$c = \frac{P}{E} = \frac{x_E - x_T}{x_P - x_T}$$

x_P U-235 concentration (by molecular fraction) in the input stream.

x_E U-235 concentration of the output product (enriched) stream.

x_T U-235 concentration of the output tail (depleted) stream.

P mass of the input stream (a kilogram in terms of the definition of a SWU

E mass of the product stream

T mass of the tail stream

(2)

TABLE 3.13 - Uncertainty Ranges

Country		Median Value	10% Probability of Being		Unit
			Less Than	Greater Than	
Japan	First Commercial Service Year	1992	1990	1995	
	Total Capital Cost	623 000		742 000	$/(tSWU/yr)
	Fixed O&M Cost	16 000		16 000	$/(tSWU/yr)
	Variable O&M Cost	17 000		17 000	$/tSWU

(3) Design Capacity and Specific Costs

Design capacity and specific costs of the systems have been calculated taking into account the availability factors given in the characterization summary tables.

(4) Total Capital Cost

As already mentioned in the system description, the construction of the 1000 t SWU/yr commercial enrichment plant is part of a common project of Dutch, British and German companies.
The technical feasibility of the centrifuge enrichment has been demonstrated since 1973 in a 45 t SWU/yr test facility at Almelo and since 1977 in two 200 t SWU/yr demonstration plants at Almelo and at Capenhurst. The specific investment costs of these facilities have been:

test facility	(45 t SWU/yr):	2.10^6 $/(t SWU/yr)
demonstration plan	(200 t SWU/yr):	890 000 $/(t SWU/yr)

The investment costs for the 1000 t SWU/yr commercial plant are estimated at 625 000 $/(t SWU/yr). A further expansion of the commercial plant to a capacity of 2000 t SWU/yr after 1985 is expected to cost 440 000 $/(t SWU/yr).

3.5.8 Fabrication of LWR Fuel

Source material for the fabrication of the LWR fuel assemblies is enriched uranium hexafluoride. It is delivered from the enrichment factory and has to be converted to uranium dioxide. (UO_2). The dominant method for UF_6 to UO_2 conversion is a wet process that involves an intermediate ammonium diuranate (ADU) compound. The process (termed ADU-process) consists essentially of 6 steps:

1. The UF_6, received as a frozen solid, is vapourized by heating it to about 100°C.

2. The vapourised UF_6 is reacted with water to form UO_2F_2.

3. Ammonia, carbon dioxide, and water are used to convert the UO_2F_2 into ADU ($(NH_4)_4(UO_2(CO_2)_3)$).

4. The yellow ADU slurry is concentrated by centrifuging or filtering.

5. The ADU is then thermally converted to U_3O_8 (calcined) in a fluidized bed furnace.

6. The U_3O_8 is heated in a hydrogen atmosphere at about 550°C to form UO_2.

In a second stage of the fuel assembly fabrication, the UO_2 powder is mechanically processed into fuel pellets and finally inserted into claddings. The seven steps of this mechanical processing stage are:

1. Grind the UO_2 powder to reduce the particle size.

2. Press the powder into pellets.

3. Sinter the pellets in a furnace at temperatures of more than 1700°C, to produce material of the required density and strength.

4. Grind the hard pellets to specified dimensions (approximate dimensions of the pellets: 12 mm in diameter, 25 mm in length; accuracy: $\pm$ 10 to $\pm$ 25 µm in diameter.

5. Wash and dry the pellets.

6. Load the pellets into the cladding and seal the ends of the tubes.

7. Form a fuel assembly from a number of tubes.

Figure 3.9 shows a block diagram of the LWR fuel fabrication process, employing the ADU-process for the UF_6 to UO_2 conversion.

Three characterizations of the LWR fuel fabrication process have been provided; these are (country name in brackets):

(1) LWR fuel assembly fabrication from uranium dioxide (Belgium).

(2) LWR fuel assembly fabrication from uranium hexafluoride (UF_6) (Japan).

(3) LWR fuel assembly fabrication from uranium hexafluoride (UF_6) (U.S.A.).

TABLE 3.14 - Technical and Economic Data of LWR Fuel Fabrication Plants

Country	Design Capacity	Annual Input	Capacity Factor	Maximum Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	tU/yr	tU	%	%	$/(tU/yr)	$/(tU/yr)	$/tU	years
Belgium[1)]	1000	707	70	70	141 650	22 000	-	20
Japan	300	183	60		313 000	83 000	193 000	15
U.S.A.	730	518	70	70	220 000	67 000	150 000	15

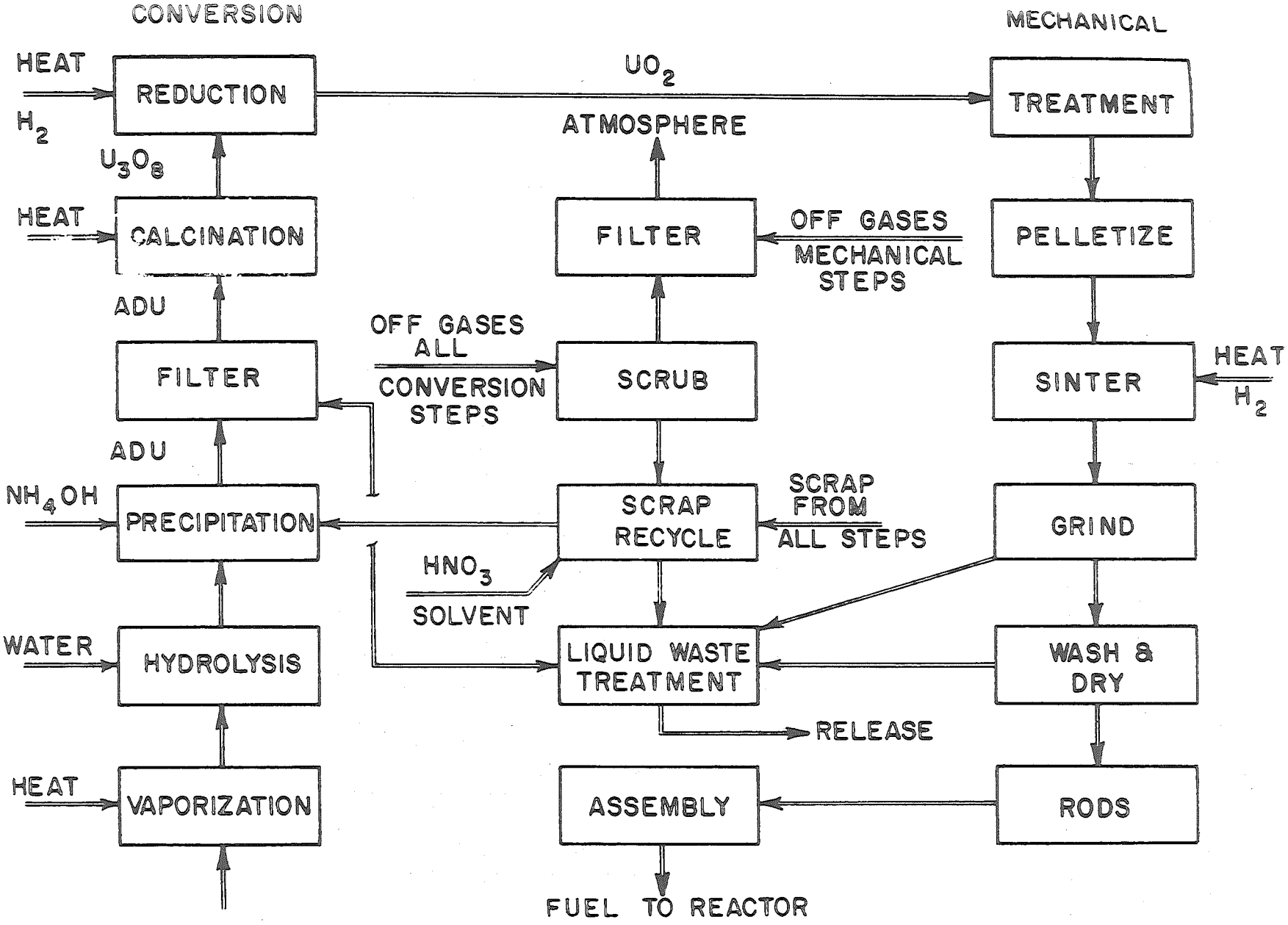


Figure 3.9: LWR fuel assembly fabrication

Assessors

Belgium:- Hecq, St., Voie du roman pays, 34; B-1348 Louvaine-La-Neuve

Japan:- Yasukawa, S., JAERI, Tokyo, Japan

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) The Belgian system does not contain the UF_6 to UO_2 conversion stage.

(2) Cost Figures

The cost figures for the Japanese LWR fuel fabrication plant are significantly higher than those of the similar American system, and also higher than those of an already existing plant in Japan. This is due to the assessor's expectations of increasing material costs. For comparison, table 3.15 shows the economic data for the existing Japanese LWR fuel factory.

TABLE 3.15 - Cost Data of an Existing Japanese LWR Fuel Factory

Item	Value	Unit
Construction Cost	142 000	$/(tU/yr)
Total Capital Cost	153 000	$/(tU/yr)
Fixed O&M Cost	83 000	$/(tU/yr)
Variable O&M Cost	52 000	$/(tU/yr)

3) Uncertainty ranges were not specified.

3.5.9 High Temperature Reactor Fuel Fabrication

As already described in section 3.3 of this report, most of the applicable fuel cycles for the high temperature reactor (HTR) involve the element thorium (Th-232) as breeding material. Thorium is a heavy, silvery metal. Estimates of its content in the earth's crust range from 5 to 13 part per million (ppm) with the element widely distributed in small quantities. Thorium occurs naturally in a variety of chemical forms, the most common of which are $ThPO_4$ (the chemical form found in monazite), $Th\ O_2$ and thorite ($Th\ Si\ O_4$). Thorium is obtained from three main sources:

- monazite, a mixture of rare metals often found in sand or gravel deposits
- as by-product of uranium mining
- veins containing thorite.

In the past the exploration for thorium resources has been minimal because the thorium available as a by-product from uranium and titanium mining has been sufficient to meet the small demand. In general, thorium exploration techniques are similar to those applied for uranium as described in section 3.5.2.

These methods rely in the main on the radioactivity of the thorium; also, more traditional methods are applied for examination and sampling.

In thorium mining, different techniques are applied, depending on whether the thorium is obtained from thorite veins or monazite deposits. The extraction of thorite will generally be done by conventional mining techniques, either open cast or underground. The water-insoluble monazite, on the other hand, accumulates with other minerals on river bottoms or ocean beaches. In these deposits, placer mining methods are normally applied. In essence, the material is simply gathered by shovel, dragline or dredge.

In a next step, the mined thorium ore is converted to thorium dioxide. This process normally includes a series of chemical treatments that start by dissolving the thorium and other remaining materials in acid. Through solvent extraction the thorium (in form of thorium nitrate) is then separated from other materials. The final step involves milling the thorium nitrate to produce ThO_2.

As already noted in section 3.3.1, there exists a great variety of possible HTR nuclear fuel cycles. All of them, except the low enriched cycle, involve thorium dioxide as the breeding material. The decision as to which of these fuel cycle concepts are finally adopted for high temperature reactors is mainly influenced by political restrictions in the respective countries. For this reason it is at present not possible to give any generally accepted statement about the final nuclear HTR fuel supply.

The intentions of those IEA-ETSAP participants who supplied characterisations, can be summarized as follos:

- Japan will apply the low enriched uranium fuel cycle for its VHTGR.

- In Germany and the United States the high temperature reactors are fuelled with high enriched nuclear fuel, involving thorium, U-235 and re-cycled U-233 as breeding respectively fissioning material.

However, there exist essential differences in the HTR fuel fabrication processes in Germany and the United States. In Germany, two different fuel concepts have been developed: the so-called one-particle concept, involving mixed oxide Th/U particles; and the two-particle concept with separate uranium burn-up and thorium breeding particles. The particles are coated by a series of pyrocarbon layers and, if need be, by an additional SiC-layer, to provide improved containment of fission products. The coating of the particles with pyrolytic carbon (BISO) and the additional SiC barrier (TRISO) is done in a fluidized bed furnace at tempera-

tures around 2000°C. Subsequently the fuel particles are pressed to spherical fuel elements about 60 mm diameter, consisting of a fuel zone 50 mm diameter and a fuel free outer zone of 5 mm tickness.

In the American HTR fuel concept, the U-235, thorium and the re-cycled U-233 are formed into two other types of microspheres, one TRISO-particle containing pure U-235 and one BISO- particle containing a combination of thorium and U-233. To form pellets, the two types of microspheres then are blended together and poured into molds with a carbonaceous 'binder'. Finally, these pellets (also termed fuel rods) are positioned in holes of machined graphite blocks. Approximately 2000 fuel rods are needed to fill a single fuel element.

A characterization of the American HTR fuel fabrication process has been submitted for this report. Feedstocks for the process are thorium nitrate and uranium hexafluoride. The process includes calcination, coating, blending, preparation of fuel rods, loading into graphite fuel elements, and heat conditioning. The essential technical and economic data are presented below, in table 3.16.

TABLE 3.16 - Technical and Economic Data of the American HTR Fuel Fabrication Process

	Capacity	First Commercial Year	Annual Input		Capacity Factor	Maximum Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
			Thorium Nitrate	Uranium Hexafluoride						
Unit	tHM/yr	-	t	t	%	%	$/(tHM/yr)	$/(tHM/yr)	$/tHM	yrs
	545	1995	367.5	14	70	70	1,080,000	54,000	80,000	15

Assessor

Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973, U.S.A.

3.5.10 Fabrication of Mixed Plutonium Oxide/Uranium Oxide

In this fuel, the fissile plutonium isotopes Pu-239 and Pu-241 replace the fissile U-235 of the pure uranium fuel. The plutonium has to be mixed with the uranium as homogenously as the uranium isotopes U-235 and U-238 in pure uranium fuel.

Basically there exists two techniques for the fabrication of uranium/plutonium fuel:

- mechanical mixing of UO_2 and PuO_2 powders,
- co-precipitation of uranium and plutonium from solutions and subsequent conversion to oxide.

The co-precipitation process has a tendency to produce non-homogeneities, hence the mechanical mixing process is preferred at present. The fuel powder produced (fissile material concentration: 2-4 %) is then pressed to pellets which, after sintering and grinding, are filled into stainless steel cladding tubes. Although the mixed oxide fuel fabrication employs the same production techniques as the uranium fuel fabrication, safety regulations are much more stringent. This is due to the high radiotoxicity of the plutonium which requires a special containment whenever plutonium is handled.

Fuel containing plutonium is mainly needed for the fast breeder reactor system which has been discussed in section 3.4. As described there, the breeder fuel consists of two different types of fuel elements; the element containing UO_2 and $Pu\ O_2$ is used in the reactor core; the other element containing depleted uranium from the enrichment factories is used in the blanket. The fabrication of the $UO_2/Pu\ O_2$ mixed oxide fuel elements has been described above. The production of the blanket elements involves both chemical and mechanical processing and is similar to the fuel fabrication process described in section 3.5.9. The depleted UF_6 is converted to UO_2 by successive reactions using water and

ammonia. The product of these reactions is heated to a high temperature to produce the UO_2 powder. Processing the UO_2 into fuel pellets follows the same process as that for mixed oxide powder.

Four characterizations of plutonium mixed oxide fuel fabrication plants have been supplied. One describes a plant producing ATR fuel, the others deal with the production of LMFBR fuel assemblies. The following systems have been characterized (country name in brackets):

(1) ATR Mixed Oxide Fuel Fabrication (Japan)
(2) LMFBR Mixed Oxide Fuel Fabrication (Belgium)
(3) LMFBR Mixed Oxide Fuel Fabrication (Japan)
(4) LMFBR Mixed Oxide Fuel Fabrication (U.S.A.)

TABLE 3.17 - Technical and Economic Data of Plutonium MOX Fuel Fabrication Plant

Country	Design Capacity	First Commercial Service Year	Annual Input		Capacity Factor	Maximum Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
			Heavy Metal	Electricity						
Unit	tHM	-	tHM	PJ	%	%	$/(tHM/yr)	$/(tHM/yr)	$/tHM	yrs
Japan ATR Fuel	300	-	203	0.47	67	80	1,400,000	125,000	←	20
Belgium LMFBR Fuel	200	1990	162	-	80	80	1,375,000	280,000	←	25
Japan LMFBR Fuel	300	-	203	1.5	67	80	1,966,000	228,000	←	20
U.S.A. LMFBR Fuel	385	1995	269.5	-	70	70	1,376,000	182,000	←	15

Assessors

Japan:- Beguchi, M., PNC, Tokyo
Belgium:- Hecq, St., Voie du roman pays, 34, B-1348 Louvaine, La-Neuve
U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) Input

The exact input of the American LMFBR fuel production plant consists of
- 245 t/yr uranium hexafluoride (UF_6)
- 24,5 t/yr plutonium oxide (UF_6)

(2)

TABLE 3.18 - Uncertainty Ranges

Country	Item	Median Value	10% Probability of Being		Unit
			Less Than	Greater Than	
Japan (HTR Fuel)	Capacity Factor	67	60	80	%
	Total Capital Cost	1,400,000	1,049,000	1,746,000	$/(tHM/yr)
	Fixed O&M Cost	125,000	94,000	156,000	$/(tHM/yr)
	Economic Lifetime	20	15	25	yrs
Japan (LMFBR Fuel)	Capacity Factor	67	60	80	%
	Total Capital Cost	1,966,000	1,474,000	2,453,000	$/(tHM/yr)
	Fixed O&M Cost	228,000	171,000	285,000	$/(tHM/yr)
	Economic Lifetime	20	15	25	yrs

3.5.11 Reprocessing Spent Nuclear Fuel

The basic purpose of reprocessing the spent nuclear fuel is to recover the unused nuclear materials and the created fission materials (plutonium, U-233) from the discharged reactor fuel; and to separate the radioactive fission products. The reprocessed fissile materials are recycled to produce new nuclear fuel. The separated fission products are solidified and stored. The economic importance of the spent fuel reprocessing hence ties in the recovery of the unused nuclear fuel material.

Reprocessing spent nuclear fuel consists, in principle, of the following process steps:

- Discharge and temporary storage of the spent fuel elements.
  The fuel element storage serves as a buffer to provide an even workload for the reprocessing plant. Additionally, it provides for the necessary nuclear decay of the highly radioactive fission products and transuraniums before processing the spent fuel.

- Cladding removal and disintegration.
  The fuel element are mechanically chopped into short pieces. The resulting pieces are placed in a nitric acid bath which reacts with the fuel but not with the metal tubing.

- Extraction of the valuable nuclear materials (fission and breeding materials).
  A counter current extraction process is employed, which involves an organic solvent, for the recovery of the unused nuclear material from the spent nuclear fuel. If, as in the case of spent LWR fuel, uranium and plutonium have to be recovered and separated, the so-called PUREX-process (Plutonium-Uranium-Recovery by Extraction) is employed. The PUREX-process involves a phosphoric acidic ester TBP (tri-n-butyl-phosphate ($C_4H_9O_3$) PO)

as solvent which is diluted by 70 % kerosene. The solvent therefore is called TBP-30. In a nitric acid bath, the TBP-30 selectively reacts with the nitrates of uranium and plutonium, thereby extracting them from the aqueous solution. The nitrates of the fission products, on the other hand, remain in solution. As the extraction effect of one stage is not sufficient, the process is successively repeated in a serie of extraction devices.
The THOREX-process (Thorium Recovery by Extraction) is applied for reprocessing spent high temperature reactor fuel. In principle, it operates like the PUREX-process, also using TBP as solvent.

- Final cleaning of the recovered fissile materials.

If necessary, the solidification of the end products follows a similar route as the last process stage of fuel reprocessing.

Five nuclear fuel reprocessing plants have been supplied.
These are (country name in brackets):

1. LWR Spent Fuel Reprocessing (Belgium)

2. LWR Spent Fuel Reprocessing (Japan)
   The system consists of a spent fuel storage facility, a reprocessing unit and a waste solidification and storage facility. The spent LWR fuel is reprocessed by the PUREX process.

3. LWR Spent Fuel Reprocessing (U.S.A.)
   The system involves cladding removal, PUREX separation, 'disaster-proof' processing building and solidification of wastes.

4. HTGR Spent Fuel Reprocessing (U.S.A.)
   The system involves controlled burning, acid leach and solvent extraction.

5. LMFBR Spent Fuel Reprocessing (U.S.A.)
The system involves cladding removal, PUREX separation, production of uranium and plutonium oxides, 'disaster-proof' processing building, and waste storage.

6. LMFBR Spent Fuel Reprocessing (Belgium)

TABLE 3.19 - Technical and Economic Data of Reprocessing Plants

Technology (Country)	Design Capacity	First Commercial Service Year	Capacity Factor	Max. Annual Availability	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
	tHM/yr	-	%	%	$/(tHM/yr)	$/(tHM/yr)	$/tHM	yrs
LWR Spent Fuel Reprocessing (Belgium)	75*	1987	70	70	4,570,670*	433,600	←	25
LWR Spent Fuel Reprocessing (Japan)	2190	1991	54.8		2,890,000	66,000	14,000	14
LWR Spent Fuel Reprocessing (U.S.A.)	1825		70	70	3,240,000	74,000	14,000	15
HTGR Spent Fuel Reprocessing (U.S.A.)	365		70	70	2,780,000	63,000	12,000	15
LMFBR Spent Fuel Reprocessing (U.S.A.)	1156		70	70	3,730,000	84,000	16,000	15
LMFBR Spent Fuel Reprocessing (Belgium)	75		70	70	14,587,000	1,387,000	←	25

*the capacity of the Belgian reprocessing plant is given in terms of tonnes spent LWR fuel, not in terms of tonnes heavy metal (tHM) input. Accordingly, the specific cost have also been related to the input of spent LWR fuel.

Assessors

Belgium:- Hecq, St., Voie du roman pays, 34, B-1348 Louvaine La-Neuve
Japan:- Yasukawa, S., JAERI, Tokyo
U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory, Upton, NY 11973

Notes

(1) Design Capacity

The capacity figures refer to the input of spent heavy metal per annum.

(2) Outputs

The output slate for full time operation of the reprocessing plants is:

o LWR Spent Fuel Reprocessing Plant (Belgium)

- for the reprocessing in a once-through cycle:

Wastes	2390 kg
U-235	645 kg
Plutonium	487 kg

- for the reprocessing with a subsequent plutonium recycling:

Wastes	2390 kg
U-235	80 kg
Plutonium	1930 kg

o LWR Spent Fuel Reprocessing Plant (Japan)

Depleted Uranium	2150 tU
Plutonium	12 tPu

o LWR Spent Fuel Reprocessing Plant (U.S.A.)

Uranium (in UF_6)	1680 tU
Plutonium (in PuO_2)	44 tPu
Calcined Fission Products	97 t

o HTGR Spent Fuel Reprocessing Plant (U.S.A.)

Thorium (in acqueous nitrate)	344 tTh
Uranium (in U-233 acqueous nitrate)	13.5 tU
Calcined fission products	7.5 t

o LMFBR Spent Fuel Reprocessing Plant (U.S.A.)

Uranium (in UO_2)	973 tU
Plutonium (in PuO_2)	110 tPu
Calcined Fission Products	73 t
and other radioactive wastes	

o LMFBR Spent Fuel Reprocessing Plant (Belgium)

Heavy metal	73.1 tHM

(3) Cost Figures

The cost figures given for the Japanese LWR spent fuel reprocessing plant are those for a future large scale commercial plant. A design study is in preparation. For comparison, the assessor additionally gave the data of a smaller reprocessing plant which is operating in Japan:

Design Capacity:	210 tHM/yr
Capacity Factor:	67%
Consruction Cost:	3,336,000 $/(tHM/yr)
Interest during construction:	500,000 $/(tHM/yr)
Fixed O&M Cost:	333,000 $/(tHM/yr)

(4) Uncertainties

Uncertainty ranges were not specified by the assessors.

3.5.12 Nuclear Waste Disposal

Last important step of the nuclear fuel cycle is radioactive waste management. The purpose of the management program is to ensure that nuclear wastes do not enter the environment until their radioactivity is below harmful levels. Certain types of waste must therefore be isolated from the environment for thousands of years. Radioactive waste management is concerned with the manipulation and storage of all radioactive materials produced in the nuclear fuel cycle.

Generally radioactive wastes are classified as either 'high-level' or 'other than high-level', the distinction being based on the radioactive content of the waste. High-level waste, which contains hundreds of thousands of curies, is produced from the reprocessing plants and basically consists of the fission products. Low-level nuclear wastes are the residuals from UF_6 production, fuel fabrication, reactor operation and fuel reprocessing.

In the following, the main data of a high-level waste storage and high-level waste disposal are summarized. The high-level waste storage consists of a storage facility located 1000 meters underground, in which solidified high-level nuclear wastes are stored for several decades until the radioactivity is low enough for the wastes to be transferred to the disposal facility. In the disposal facility the high-level wastes are temporarily (20-30 years) stored in a repository more than 600 meters underground and finally transferred to a repository for permanent disposal.

Table 3.20 summarizes the data of both waste storage facility and disposal facility.

TABLE 3.20 - Technical and Economic Data of High-Level Nuclear Waste Storage and Disposal

	Design Capacity	First Commercial Service Year	Annual Input of Electricity	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Amortization Lifetime
Unit	tx	-	TJ	$/tx	$/tx	$/tx	years
High-level waste storage	1,670	1990	24	100,400	1,200	300	13
High-level waste storage	22,500	2030	9.7	1,460	110	120	13

Assessor

Japan:- Yasukawa, S., JAERI, Tokyo

Notes

(1) Units

tx = tonnes (spent fuel equivalent)

(2) Annual Input of Electricity

Input electricity is used for air conditioning of the repository transportation, etc.

3.6 References

/3.1/ Energy Alternatives: A Comparative Analysis Science and Public Program, University of Oklahoma, Norman, 1975

/3.2/ Pickert, F.K., Zech, H.-J.: Brennstoffkreislauf, Deutsches Atomforum e.V., Bonn, 1981

/3.3/ Schmitt, D., Junk, H.: Aktualisierung der Parameterstudie zur Ermittlung der Stromerzeugungskosten aus Steinkohle und Kernenergie

/3.4/ Studie über die Wirtschaftlichkeit der Stromerzeugung mit Hochtemperaturreaktoren, Red. G. Kolb, Jül-1527, August 1978

/3.5/ Engelmann, P., et al.: Uranverbrauch und Kosten langfristiger HTR-Strategien im Vergleich zu LWR und SBR; Jül-1612, August 1979

/3.6/ Nuclear Power Issues and Choices. Report of the Nuclear Energy Policy Study Group; Ballinger Publishing Company; Cambridge, Massachusetts, 1977

4. SYNFUELS FROM COAL/BIOMASS AND OIL REFINING

4.1 Classification of Gaseous Fuels from Coal

Gaseous fuels with low, medium or high energy content can be produced from coal. No fixed calorific values are associated with these classifications; however in Table 4.1 representative ranges are given for gross calorific values.

TABLE 4.1 - Gas Classification by Calorific Value

Gas Type	Gross Calorific Value BTU/SCF (a)	Gross Calorific Value MJ/Nm³ (b)
Low calorific value gas (low BTU gas)	less than 250	less than 10
Medium calorific value gas (MCG) (medium BTU gas)	250 - 650	10 - 25
Substitute natural gas (SNG) (high BTU gas)	900 - 1050	35 - 42

(a) SCF standard cubic feet of gas - measured at 60 °F and 760 mm Hg absolute pressure

(b) Nm³ normal cubic metres of gas - measured at 0 °C and 760 mm Hg absolute pressure

1×10^6 SCF = 26800 Nm³

1×10^6 BTU = 1.0546 GJ

1000 BTU/SCF = 39.35 MJ/Nm³

4.2 Gasification Process Types

Low and medium calorific value gases are produced in a two-stage process involving coal preparation and gasification. A third stage, raw gas upgrading, is required to produce substitute natural gas (SNG) of 'pipeline' quality. These three stages are illustrated in Figure 4.1 (Ref. 4.1) and are described below with extracts from References 4.1, 4.2, and 4.3.

4.2.1 Pretreatment

This depends on the particular gasification process. In addition to coal handling and storage, pretreatment may simply mean drying and pulverizing or may involve a mild pre-oxidation to prevent the coal from agglomerating into a plastic mass at the bottom of the gasifier (caking). Most bituminous coals have some caking properties that cause difficulty if pre-oxidation is not used. With such oxidation there is a loss of heating value in the range 10 to 15 per cent of that of the original coal.

Pretreatment may also involve slurrying with water.

4.2.2 Gasification

In the gasifier some of the input coal is burnt with oxygen to provide the process heat for the endothermic reaction between carbon and steam, which produces carbon monoxide (CO) and hydrogen (H_2). In addition, there are reactions between the input coal and the hydrogen to produce methane (CH_4) in the gasifier itself.

Methane, the primary component of natural gas, is similar to natural gas in heating value. Carbon monoxide and hydrogen heating values are approximately equal, being about one-third the methane/natural gas value. Several non-combustible gases are also produced, including carbon dioxide, hydrogen sulphide, and nitrogen.

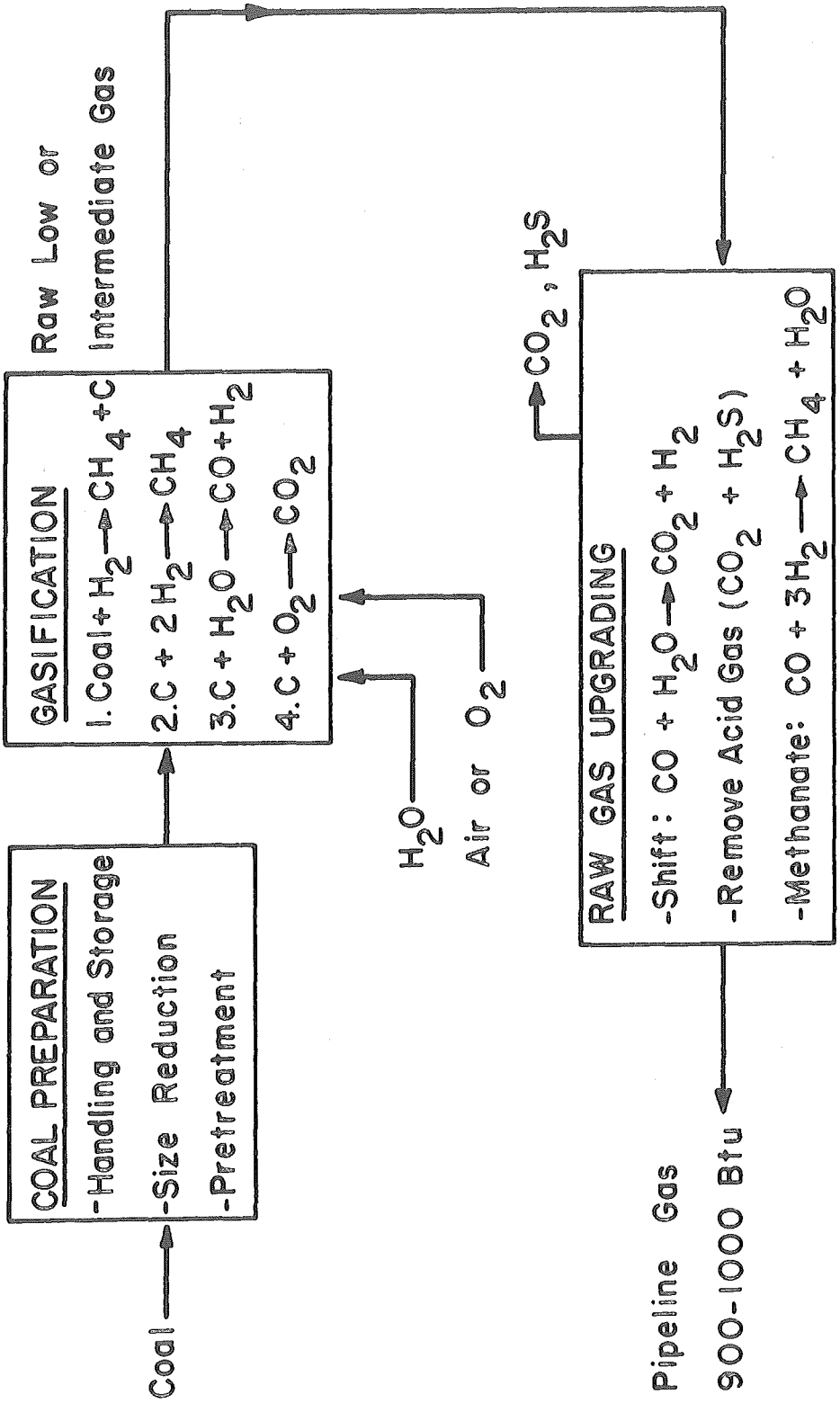


Figure 4.1: General Process Scheme for Producing Gas from Coal (Ref. 4.1)

A major goal for most coal gasification processes is to produce a high quality gas during the initial gasification stage. The product from each process is determined primarily by the methods used to introduce hydrogen, oxygen, and heat into the gasifier. Each method involves trade-offs. For example, if air is used to provide the oxygen (as in a low calorific value gasifier), nitrogen is produced as an undesirable by-product and the heating value of the gas is reduced. Although pure oxygen is more expensive than air, it eliminates the nitrogen problem and produces medium calorific value gas rather than low calorific value gas.

The use of steam to introduce hydrogen into the process produces primarily carbon monoxide and hydrogen, while the direct introduction of hydrogen produces methane and carbon in an exothermic devolatization reaction. Since the latter process does not produce large amounts of methane it is normally placed in a pretreatment stage. The steam-carbon reaction is used more frequently to produce final product low/medium calorific value gases and to produce feedstocks for high calorific value gasification.

For coal gasification processes, direct heat is more thermally efficient than indirect heat. However, most direct heat processes use either air or oxygen as an oxidiser, producing the products and problems identified above. Indirect heating using molten salts, dolomite solids, molten slag, pebbles etc. introduces additional materials requirements and makes the gasification more complicated.

As indicated above, the basic chemical choices are whether to use hydrogen or steam, air or oxygen, and direct or indirect heat.

Gasification systems can also be categorized on the basis of engineering features, two significant ones being whether the system is pressurized and the type of bed used. Gasification systems can be operated either at high pressure or at atmospheric pressure. The main advantages gained from pressurizing

are improving the quality of product gas, maximization of the hydrogasification reaction ($C + 2H_2 \rightarrow CH_4 + Heat$), and elimination of the need to separately pressurize gas before introducing it into the pipeline.

In terms of beds, there are three basic types of gasification systems: fixed-bed, fluidized-bed, and entrained bed. In the fixed-bed system, a grate supports lumps of coal through which the steam or hydrogen is passed. Conventional fixed-bed systems are incompatible with caking coals. To expand the range of coals that can be used, some fixed-bed systems are modified to incorporate a rotating grate or stirrer to prevent caking.

The fluidized-bed system uses finely sized coal. Gas flows through the coal, producing a lifting and "boiling" effect. The result is an expanded bed with more coal surface area to promote the chemical reactions. Fluidized-bed systems also have a limited capacity for operating with caking coals; consequently, these types of coals are often pretreated to destroy caking characteristics when the fluidized-bed system is used.

Finely sized coal is also used in entrained-bed systems. In this type of system, the coal particles are transported in the gas (for example, steam and oxygen) prior to introduction into the reactor. The chemical reactions occur, and the product gases and ash are taken out separately. There are no limitations on the types of coal that can be used with the entrainment system.

4.2.3 Acid Gas Removal and Sulphur Recovery

In medium calorific gas (MCG) production the stage after gasification is acid gas removal and sulphur recovery (Figure 4.2). In SNG production a shift conversion stage (Section 4.2.4) intervenes (Figure 4.2). In the acid gas removal stage the gas is purified by removal of carbon dioxide and hydrogen sulphide. In SNG production the gas is purified to less than 1.5 per cent

carbon dioxide by volume and less than 1 ppm of hydrogen sulphide. Sulphur can be recovered from the hydrogen sulphide. The acid gas removal step has a measurable effect on the economics of SNG and MCG production both directly in terms of capital investment and indirectly in terms of steam and power consumption.

4.2.4 Shift Conversion

This stage occurs in SNG production. Shift conversion combines carbon monoxide and water to produce carbon dioxide and hydrogen. This shift is necessary to adjust the hydrogen and carbon monoxide to the 3:1 ratio required for methanation. A catalyst, usually an iron-chromium oxide compound, is used in this reaction.

4.2.5 Methanation

This stage occurs in SNG production only. Carbon monoxide and hydrogen are reacted using (typically) nickel compounds as catalysts to produce methane. Water vapour is then removed to give a product substitute natural gas. With both the dry-ash Lurgi and British Gas Lurgi Slagging processes the gas is compressed to a compatible 68 atm delivery pressure.

4.3 Low/Medium Calorific Value Gasification

Four technology characterizations of low/medium calorific value gasification processes were submitted by project participants. These were (country shown in brackets):-

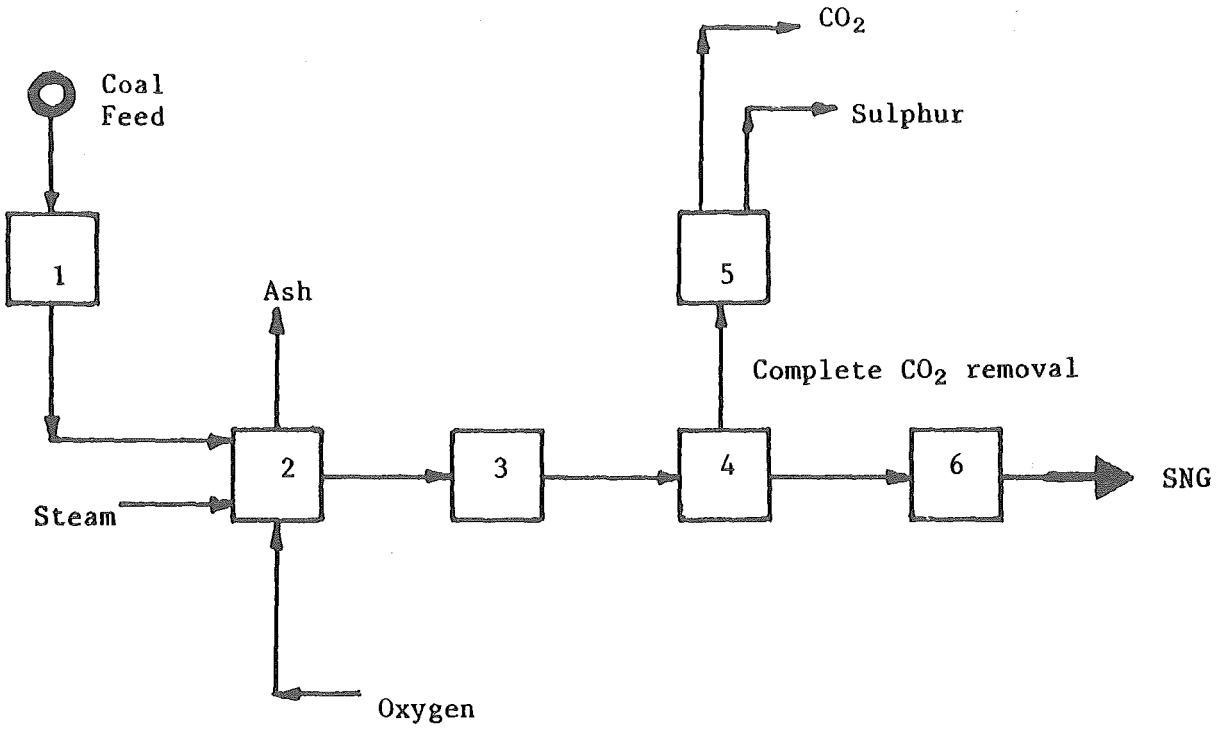
(i) Low/medium Btu gasification, process not specified (U.S.A.)

(ii) Koppers-Totzek (Germany)

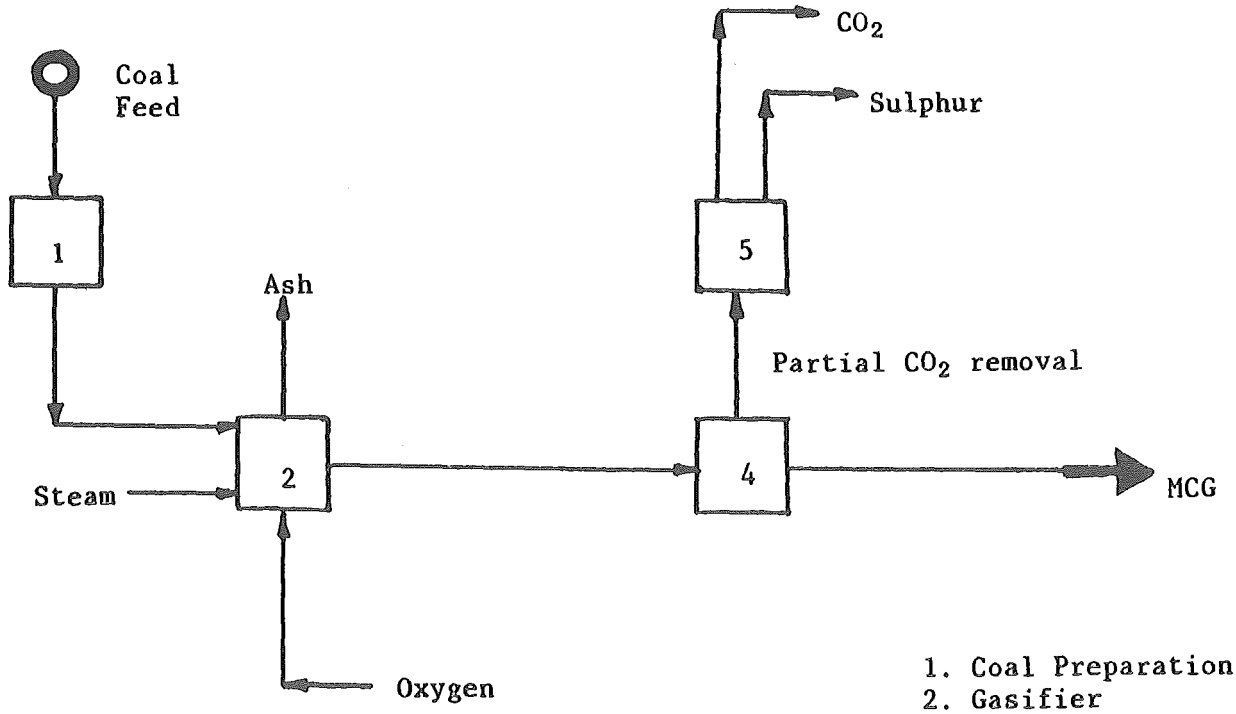
(iii) Shell-Koppers (Germany/Belgium from IEA/EAS Sources)

(iv) British Gas/Lurgi Slagging Gasifier (U.K.)

SNG Production



MCG Production



1. Coal Preparation
2. Gasifier
3. Shift conversion
4. Acid gas removal
5. Sulphur recovery
6. Methanation

Figure 4.2: SNG and MCG Production (Ref. 4.3)

The Koppers-Totzek process is an entrained flow, atmospheric pressure, direct burning system.
The Shell-Koppers process is a development on the Koppers-Totzek system operating at a pressure of 20-40 atmospheres.

The British Gas Corporation - Lurgi Slagging process is a pressurized fixed bed system with the normal Lurgi revolving grate, lock-hopper ash removal system replaced by a slag tap and quench chamber and with tuyeres to inject high velocity steam and oxygen.

Expanded descriptions of these processes are given in sections 4.3.1, 4.3.2, 4.3.3 and key data from the characterization questionnaires are presented in a summary table in section 4.3.4.

MCG processes not covered in this survey are the dry ash Lurgi fixed bed, the Texaco entrained flow and the various fluidized bed systems (Conoco CO_2 Acceptor, COGAS, HYGAS, Synthane, Winkler).

4.3.1 Koppers-Totzek

In this process caking or non-caking pulverized (70-80 % of coal passes a 200-mesh screen) coal is mixed with oxygen and steam (entrained suspension) and then pumped into an atmospheric pressure vessel gasifier through burner heads. Combustion occurs at high temperatures (1600 °C - 1900 °C) and the product gas (gross calorific value 11 MJ/Nm³) exits upwards through a central vertical outlet. Molten slag exits at the bottom. Typical output gas composition is (dry %)

	%
CO	52
CO_2	10
H_2	36
Non-fuel gases	2

Coal processing capacity varies depending on the number of burner heads used. A four headed gasifier can process about 850 tons of coal/day.

There are several advantages of K-T units and the commercialization of the process during the 1950s at a time when cheap competing fuels were readily available attest to this. The following advantages should be noted.

a. Good safety record.

b. The gasifier is relatively simple and flexible.

c. Little effect on the gasification process due to physical properties of the feed coal, such as fines, ash fusion temperature, ash content etc.

d. Rapid start-up and shut-down capability.

Disadvantages of the K-T process include:

a. Low thermal efficiency.

b. Limitation of feed coal to 10 per cent moisture.

c. Lack of data on high quality coals.

d. Relatively high cost of energy.

e. Operation with air and steam for low calorific value gas output is not promising.

4.3.2 Shell-Koppers

The Shell-Koppers process is a development of the commercialized Koppers-Totzek process, operating at a pressure of 20-40 atmospheres. A 0.25 t/h plant has been operating at the Shell research laboratories in Amsterdam since January 1977. A 6.25 t/h plant was commissioned at Harburg, West Germany in late 1978.

The process is being developed for use in air-blown combined cycle (gas turbines plus steam turbines) applications and oxygen-blown synthesis gas production.

Most coals are suitable as feedstock after drying to 2-8 % moisture and pulverization. Coal is fed pneumatically into a refractory lined vessel with opposed firing. Liquid slag is removed from the bottom and quenched in water. Temperature at the gas outlet is 1500-1600 °C.

4.3.3 British Gas/Lurgi Slagging Gasifier

This process is a significant development of the conventional pressurized Lurgi fixed bed system. The use of a much lower steam/carbon ratio results in much higher temperatures so that the ash forms a molten slag. To handle this the lower part of the gasifier is modified and the steam and oxygen injected through tuyeres. The slag is collected in a hearth at the base of the reactor and periodically removed via an ingenious slag tap to form a glassy frit in a water filled quench chamber. The need for a rotating grate to remove ash is thereby eliminated.

The temperature of the molten slag is a function of its composition and is in the range of 1500 - 1800 °C.

The advantages of slagging fixed bed gasification arising from the lower steam utilisation include higher gasifier throughput (around a factor of four) and hence a saving in gasifier capital costs, higher thermal efficiency and lower liquor production. The latter simplifies and cheapens effluent disposal.

The coal feed is by lock hopper and distributor as for the conventional Lurgi process and the advantage of the fixed bed gasifier, that the bed acts as a heat exchanger and the coal is preheated by the product gas, is retained. The preferred requirement of the conventional Lurgi gasifier for weakly caking, high reactivity, high ash fusion point coal is relaxed for the Slagging Gasifier and most coals can be accepted.

One of the Lurgi Gasifiers of the Westfield, Scotland town gas plant, was lined to reduce its diameter (although its throughput was considerably increased) and converted to slagging

operation. The first run took place in April 1975 as part of a project sponsored by Conoco, and a consortium of US companies. At the end of the 4 year test programme, a commercial scale demonstration plant was designed for the US companies. At the end of the 4 year test programme, a commercial scale demonstration plant was designed for the US Department of Energy. British Gas have continued the development of Slagging Gasifier with the ultimate objective of its use for the production of SNG when needed for the UK. A 90 day proving run was successfully completed in December 1981.

4.3.4 Low/Medium Calorific Value Gasification of Coal - Characterization Summary

TABLE 4.2 - Low/MCG from Coal - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Germany (Koppers-Totzek)	73.9	c.a.	63.3	85.6	85.6	58.2	14.7	0.79	0.67	20
Germany/Belgium from IEA/EAS source (Shell-Koppers)	15.1	1995	12.9	85	85	69.1	12.2	0.97	←	20
U.K. (British Gas/Lurgi slagging gasifier)	66.3	1985	60	90	90	75	16	0.4	1	20
U.S.A.	85		76.5	90	90	75	20.8	0.7	0.26	30

(c.a. = currently available)

Assessors

Germany:	-	Walbeck, M. and Martinsen, D., KFA/STE, Postbox 1913, 5170 Jülich,
Germany/ Belgium:	-	Müller, M. and Altdorfer, F., KFA/STE, Postbox 1913, 5170 Jülich,
U.K.:	-	Ward, A.V., ETSU, Harwell,
U.S.A:	-	Bhagat, N., Brookhaven National Laboratory, Upton, NY 11973

Notes:

(1) All energy quantities based on NCV of fuels.

(2) Shell-Koppers:

Design Capacity: 500 MW net output = 15.77 PJ/yr, based on high calorific value of 12 MJ/Nm³ (p. 177 Reference 4.3). Assuming a gas NCV/GCV ratio of 0.96 for MCG (corresponds to gas analysis of Koppers-Totzek output), gives design capacity of 15 PJ/yr. Overall Efficiency: Original characterization, based on GCV gives efficiency = 0.691. Assuming gas NCV/GCV ratio of 0.96 and coal (Pittsburg seam bituminous) NCV/GCV ratio of 0.96 leaves efficiency unchanged. Total Capital Cost: Total construction cost, expressed in mid-1980 $ (Ref. 4.3, p. 141; for the conversion of mid-1978 to mid-1980 $, the Chemical Engineering Plant Cost Index has been used)

$$\frac{135 \times 10^6 \$_{78} \times 1.2}{15.77 \text{ GJ/yr}} = 10.27 \$_{78}/(\text{GJ/yr})$$

A Texaco MCG plant has about the same costs. A gasification plant with a Lurgi gasifier is more expensive.

Breakdown (in 10^6 mid-1980 $)	
Coal preparation and handling	9.6
Gasification and ash handling	36.0
Oxygen plant	34.8
Acid gas removal and sulphur recovery	10.8
Process condensate treatment	1.2
Steam and power generation	28.8
Cooling water system	3.6
Balance-of-plant	13.2
TOTAL	138.0
Contingency (15 %)	20.4
Process royalties (2.5 %)	3.6

- Expenditure profile

Year	%
1	10
2	22.5
3	47.5
4	20
	100.0

- 6 % interest rate

Total capital cost in original characterization is 11.7 $/GJ/a on GCV basis. Dividing by 0.96 gives 12.2 $/GJ/a on NCV basis.

Operating and Maintenance Costs: Both fixed and variable O&M costs appear under the fixed O&M cost heading in summary table 4.2 for Shell-Koppers. Total O&M cost given in original characterization as 0.93 $/GJ/a on GCV basis. Dividing by 0.96 gives 0.97 $/GJ/a on NCV basis.

O&M costs correspond to 85 % capacity factor.

$$12.18 \times 10^6\ \$_{78} \times 1.2 = 14.62 \times 10^6\ \$_{80}$$

(Ref. 4.3)

O&M cost breakdown (costs expressed in 10^6 mid-1980 $)

Water	0.55
Catalysts and chemicals	0.07
Operating labour	3.36
Maintenance	5.87
Insurance, local taxes	4.77
	14.62

(3) British Gas/Lurgi Slagging Gasifier (Ref. 4.4)

Design Capacity: The plant is designed to give 200 mscfd (2.2 GW).

Overall Efficiency: MCG production efficiency is around 75 % assuming the coal feed is NCB # 5-6 (23-26 GJ/tonne NCV)

Total Capital Cost: Based on the assumption that the capital costs of producing MCG might be 20 % less than producing SNG. Component costs (given below) are scaled accordingly.

	$/GJ/a
Construction	12
Owners costs	2.5
Interest	1.5
	16.0

Operating and Maintenance Costs: The fixed O&M cost will be approximately the same as for a SNG plant. An estimate of £ 12 x 10^6 has been taken giving 0.4 $/GJ/a. Variable O&M costs might be £ 25 x 10^6 for an output of 60 GJ/a giving approximately 1 $/GJ.

(4) Low/Medium 8tv Gasification (U.S.A.)

The assessor provided confidence limits on some items in Table 4.2 as follows:

Item	Unit	Median Value	10 % Probability of Being	
			Less Than	Greater Than
Overall Efficiency (average load)	%	75	68	82
Total Capital Cost	$/GJ/a	20.8	17.3	25.4
Fixed O&M Cost	$/GJ/a	0.7	0.5	0.95
Variable O&M Cost	$/GJ	0.26	0.20	0.35

4.4 High Calorific Value Gasification of Coal (Fossil Heat Source)

Seven technology characterizations of high calorific value gasification processes using coal as feedstock and heat source (as opposed to a nuclear heat source) were submitted by project participants. These were (country shown in brackets):-

(i) High BTU gasification, first generation technology, (e.g. Lurgi) (U.S.A.)
(ii) Dry ash Lurgi (Germany)
(iii) Dry ash Lurgi (Germany/Belgium from IEA/EAS sources)
(iv) British Gas/Lurgi Slagging Gasifier (U.K.)
(v) British Gas/Lurgi Slagging Gasifier (Germany/Belgium from IEA/EAS sources)
(vi) Fluidized/entrained bed advanced technology (U.S.A.) (e.g. CO_2 Acceptor, HYGAS, BIGAS, Synthane)
(vii) Combined concept of hydrogasification module, high temperature Winkler gasifier, brown coal power plant

An important technology omission in the above list is the Exxon Catalytic Gasification process which is a notable departure from conventional systems in that it does not require an oxygen plant, a shift converter, or a methanator.

Essentially any gasifier or process that produces MCG can also produce SNG when appropriate methanation is implemented. Gas product properties that are important in the production of SNG are 1) the ratio of H_2 to CO in the gas produced, and 2) the amount of methane already contained in the product from the gasification.

4.4.1 Dry Ash Lurgi (Ref. 4.3)

The dry-ash Lurgi process must be regarded as the most highly developed of all the processes considered. For example, the SASOL II complex in South Africa using Lurgi gasifiers, when operating, will consume as much coal as a 3000 MW SNG plant, so the process may be considered to be already full-scaled.

Even with this process development work is likely to lead to some reduction in product gas costs by using larger gasifiers or higher operating pressures. The effect of selling byproducts at prices higher than coal cost is significant in this and the British Gas/Lurgi Slagging Gasifier.

In one respect, however, new processes may be considered superior to the dry-ash Lurgi process, even if they do not appear to produce cheaper SNG. The dry-ash Lurgi process cannot handle more than a limited amount of fines. The upper limit for fines is a function not only of the size consist but also of the caking properties of the coal, as mildly caking coal tends to agglomerate the fines.

4.4.2 British Gas/Lurgi Slagging Gasifier (Ref. 4.3)

This process has been demonstrated on a substantial scale and is available with the minimum of development work. The ability of the gasifier to handle run-of-mine coal directly is superior

to the dry-ash version. Along with steam and oxygen, fine coal and recyled tar can be injected via tuyeres into a very high temperature (1800 °C) reaction zone (the raceway). Injection of up to 15 % fines has already been demonstrated and the technology is under active development to accept all the fines in run-of-mine coal.

Injection of tar into the hottest part of the gasifier raises the possibility of recycling tar to extinction. Tar can also be recycled in the dry-ash Lurgi process by adding it to the top of the bed (a common practice also used with the Slagging Gasifier) to reduce dust carry over. However, most of this tar is distilled off again and there is always a net yield of tar.

The British Gas/Lurgi slagging process offers the same benefits as the dry-ash Lurgi process in terms of relatively low oxygen consumption and significant methane production. However, one of its major potential advantages, low steam consumption, is essentially nullified by the need for additional steam for the CO shift step for SNG production if conventional Lurgi downstream equipment is used. On the other hand, it should be noted that British Gas have developed a combined shift/methanation process (the HCM process) that avoids the need for further steam injection and gives an overall process efficiency of 71 % which is 5 - 10 % better than conventional Lurgi depending on the feed. The other major advantage, high throughput acts to reduce the capital cost of the Slagging Gasifier compared to the Lurgi process.

4.4.3 Fluidized/Entrained Bed Advanced (2nd Generation) Technology

The U.S.A. characterization submitted under this heading is a 'composite' characterization of a number of candidate U.S. advanced gasification technologies (e.g. HYGAS, Synthane, CO_2 Acceptor, BI-GAS).

Caking coals can be used with these processes. (Ref. 4.2) Some of the processes that have been supported by the U.S. Government and/or industry for the production of SNG include:-

a) Fluidized Bed Systems (Ref. 4.1)

- o HYGAS (Institute of Gas Technology)
  - hydrogasifier (hydrogen introduced into the gasifier is produced by reaction of steam, char, and oxygen), oxygen blown, direct heat, 1000 psi (6900 kPa), sizing-heating-slurry pretreatment, 8 to 100 mesh fines all coals;

- o Synthane (DOE-Pittsburgh Energy Technology Centre)
  - gasifier/devolatilizer, steam as hydrogen source, oxygen blown, direct heat, 1000 psi (6900 kPa), sizing-heating-volatilizing pretreatment, all coals, fines of 200 mesh;

- o CO_2 Acceptor (Conoco Coal Development Co.)
  - gasifier/devolatilizer, steam as hydrogen source, air blown, direct and indirect heat, 150 psi (1030 kPa), sizing pretreatment, lignite or subbituminous feed;

b) Entrained Flow Systems (Ref. 4.1);

- o BI-GAS (Bituminous Coal Research Inc.)
  - gasifier and hydrogasifier, steam as hydrogen source, oxygen blown, 1000 psi (6900 kPa), liquid to rank A bituminous pulverized feed.

(Ref. 4.2) As a generalization, the principal distinguishing feature of first generation systems (Lurgi, Koppers-Totzek, Texaco, Winkler) is the relatively low CH_4 output from the gasifier. Only Lurgi produces a synthesis gas with significant amounts of methane. Second generation units consistently produce 15 per cent CH_4. Increasing the methane content decreases water-gas shift and secondary methanation requirements and decreases the quantity of waste heat generated.

Comparisons between first and second generation systems on the H_2:CO ratio are less stark. It should be noted, however, that the mean H_2:CO ratio for first-generation systems is 1.2:1, and all but the Lurgi are near or below 1:1. The mean ratio for second-generation systems is 2.2:1, with no system below 1:1. The H_2:CO ratio (ideally 3:1) again affects the water-gas shift requirement and waste heat production. It also affects process water consumption associated with the shift reaction.

4.4.4 Combined Hydrogasifier/High Temperature Winkler (Ref. 4.2, 4.5)

The Winkler is a fluidized bed unit and was the first commercial large scale process used to gasify lower rank coals and char. Since 1933 all commercial Winklers have been blown with oxygen and steam, producing medium calorific gases.
The conventional and high temperature Winkler processes have the following advantages:

- a broad variety of coals ranging from lignites to slightly caking reactive hard coals can be processed; high ash content is permissible.;
- fines and relatively coarse particles can be processed;
- low consumption of oxygen;
- gas product low in tars, HCN and ammonia;
- operation at part load (down to 35 % of design capacity) is possible;
- the reactor coal holdup is large enough so as to permit a continuous operation at full capacity up to about 1/2 hour after failure of feed coal supply. Start-up and shut-down operations are facilitated by this characteristic.

(Ref. 4.5) The conventional Winkler process is operated at atmospheric pressure, at relatively low temperatures (800-900 °C) and with a carbon conversion rate of about 90 %. These latter three features are disadvantageous for some applications.

The Rheinische Braunkohlenwerke AG (Rheinbraun) high temperature Winkler (HTW) concept was developed to overcome the above disadvantages. It operates at higher pressures (5-20 bar com-

pared with the 1.5 bar of the conventional Winkler) and higher temperatures (900-1100 °C). Increased pressure and temperature both result in a greatly increased gasification rate. Whereas conventional oxygen blown Winkler generators have been operated at gasification rates of about 60,000 Nm^3/h, future HTW gasifiers will be designed for more than 150,000 Nm^3/h of raw gas.

A pilot plant producing 1500 Nm^3/h of raw gas was designed, built and started up in mid 1978 at Frechen, Germany by Uhde GmbH.

Rheinbraun have developed a combined hydrogasifier-HTW process which avoids the methanation step in converting raw gas to SNG. This scheme which is shown in Figure 4.3 involves the hydrogasification reaction of coal with H_2 at a pressure of about 80 bar. The product gas is purified and low temperature separated to yield the product SNG, recycle hydrogen and CO which is sent to the shift. The make-up hydrogen is generated by gasifying coke from the hydrogenation process in a HTW plant. Additional coal may have to be gasified in order to satisfy the hydrogen balance. The HTW raw gas will be shifted and purified to produce hydrogen.

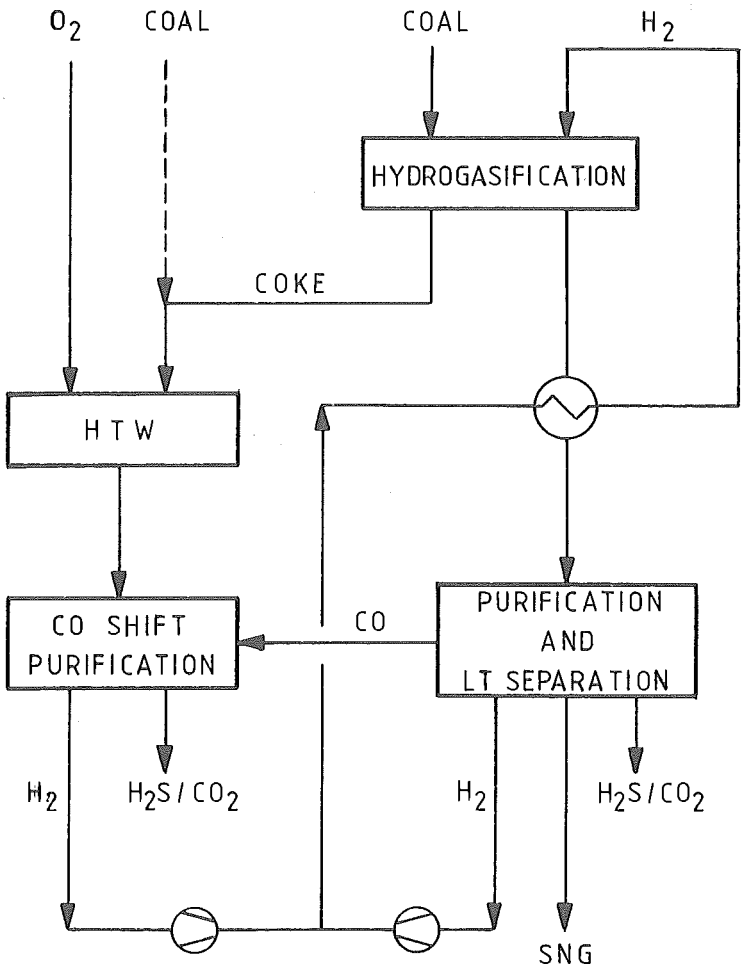


Figure 4.3: SNG Production via High Temperature Winkler and Coal Hydrogasification (Ref. 4.5)

4.4.5 SNG from Coal (Fossil Heat Source) - Characterization Summary

TABLE 4.3 - SNG from Coal (Fossil Heat Source) - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
U.S.A. (1st generation, e.g. Lurgi dry-ash)	85	1989	76.5	90	90	63	28.9	0.96	0.36	30
U.S.A. (Lurgi dry-ash)	96.3	1988	86.7		90	63	26.0	"	1.42	30
Germany (Lurgi dry-ash)	83.3	c.a.	71.3	85.6	85.6	54.4	22.9	1.06	1.14	20
Germany/Belgium from IEA-EAS source (Lurgi dry-ash)	86.6	c.a.	73.6	85		53.0	20.9	1.5	"	20
Germany/Belgium from IEA-EAS source (British Gas/Lurgi slagging gasifier)	86.6		73.6	85		54.5	17.6	1.34	"	20
U.K. (British Gas/Lurgi slagging gasifier)	66.3	1985	60	90	90	70	22	0.5	1	20
U.S.A. (2nd generation-fluidized/entrained bed)	85	1994	76.5	90	90	68	24.27	0.77	0.29	30
Germany (combined hydrogasifier-high temperature Winkler)	56.7	1990	48.5	85.6	85.6	59.7	26.0	1.11	0.93	20

Assessors

U.S.A.:- Bhagat, N., Brookhaven National Laboratory, Upton, NY 11973.

Germany:- Walbeck, M. and Martinsen, D., KFA/STE, 5170 Jülich
Germany/Belgium:- Müller, M. and Altdorfer, F., KFA/STE, 5170 Jülich
U.K.:- Ward, A.V., ETSU, Harwell, England.

Notes:

(1) All energy quantities based on NCV of fuels.

(2) Lurgi Dry-Ash:

a) The U.S.A. characterization is a generic description of 1st generation high calorific gasification of coal of which the Lurgi dry-ash process can be considered a representative technology. Caking coals cannot be used in this process.
The assessor provided confidence limits on some items in Table 4.3 as follows:

Item	Unit	Median Value	10 % Probability of Being	
			Less Than	Greater Than
First Commercial Year	-	1989	1988	1991
Overall Efficiency (average load)	%	63	58	68
Total Capital Cost	$/GJ/a	28.9	26.6	34.7
Fixed O&M Cost	$/GJ/a	0.96	0.80	1.30
Variable O&M Cost	$/GJ/a	0.36	0.30	0.50

b) In the German characterization it should be noted that, as well as the design capacity output of 83.3 PJ/a of SNG, the plant has a design capacity output of 6.7 PJ/a of residual oil. However, all values in table 4.3, including efficiency, are based on SNG output alone.

c) In the German/Belgian characterization based on IEA/EAS data (Ref. 4.3), original values were presented on a GCV basis using the conversion factors

SNG 35.4 MJ/Nm^3
Eastern coal 28.83 GJ/tonne.

For summary table 4.3 all values were converted using the NCV/GCV ratios

SNG	0.9
Eastern Coal	0.96

Total construction cost breakdown in $\$_{80} \times 10^6$ is (Ref. 4.3, p 141)

Coal preparation and handling	25.2
Gasification	396.0
Oxygen plant	156.0
Acid gas removal	139.2
Sulphur recovery	115.2
Methanation, gas compression & drying	73.0
Ash and sludge handling	4.0
Process condensate treatment	33.6
Steam and power	244.0
Cooling water system	36.0
Balance-of-plant	122.4
TOTAL	1346.4
Contingency (15 %)	201.6
Process royalties (2.5 %)	38.4
TOTAL CONSTRUCTION COST	1586.4

All operating and maintenance costs are under "fixed O&M costs". This corresponds to an 85 % capacity factor.

Breakdown of O&M costs is

Water	3.74
Catalysts and chemicals	11.62
Operating labour	6.72
Maintenance	47.73
Insurance, local taxes	38.70
	108.51 x 10^6 $\$_{78}$

Costs updated from mid-1978 to mid-1980 values using US chemical engineering plant cost index (1.2).

(3) British Gas/Lurgi Slagging Gasifier:

a) In the German/Belgian characterization based on IEA/EAS data (Ref. 4.3), original values were presented on a GCV basis using the conversion factors

SNG	37.9 MJ/Nm^3
Eastern Coal	28.83 GJ/tonne

For summary table 4.3 all values were converted using the NCV/GCV ratios

SNG	0.9
Eastern Coal	0.96

Total construction cost breakdown in $\$_{80} \times 10^6$ is (Ref. 4.3, p 141)

Coal preparation and handling	22.8
Gasification	234.0
Oxygen plant	152.4
Acid gas removal	150.0
Sulphur recovery	115.2
Methanation, gas compressing and drying	82.8
Ash and sludge handling	3.6
Process condensate treatment	18.0
Steam and power	223.2
Cooling Water System	30.0
Balance-of-plant	103.2
TOTAL	1135.2
Contingency (15 %)	170.4
Process royalties (2.5 %)	32.4
Construction Cost	1338.0

All operating and maintenance costs are under "fixed O&M costs". This corresponds to an 85 % capacity factor.

Breakdown of O&M Cost (Cost in 10^6 mid-1980 $)

Water	4.26
Catalysts and chemicals	17.11
Operating labour	7.39
Maintenance	48.30
Insurance, local taxes	39.15
TOTAL	116.21

Average annual personal costs correspond to 33600 $/person.

b) U.K. characterization based on the account given in Ref. 4.4.

The efficiency of 70 % given in the characterizati summary table is appropriate with UK coal in UK co ditions.

Costs have been updated from 1977 valves by a factor based on RPI movements of 1.45. Capital cost breakdown is

	£ M
Construction Cost	480
Owners Costs	100
Interest During Construction	50
	630

. This gives 22 $/GJ/a.

The assessor comments that it is not easy to distinguish fixed and variable O&M costs. Based on Ref. 4.4, fixed O&M might be £ 14 x 10^6, variable O&M £ 26 x 10^6.

(4) Fluidized/Entrained Bed:

The U.S.A. characterization is a generic description of advanced 2nd generation high calorific gasification of coal using higher pressures and a fluidized/entrained bed. Caking coals can be used. Examples of such a technology are the CO_2 Acceptor, HYGAS, BI-GAS and Synthane processes.

The assessor provided confidence limits on some items in Table 4.3 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
Overall Efficiency (average load)	%	68	62	75
Total Capital Cost	$/GJ/a	24.27	22.0	34.7
Fixed O&M Cost	$/GJ/a	0.77	0.65	1.30
Variable O&M Cost	$/GJ	0.29	0.25	0.50

(5) Combined Hydrogasifier/HTW:

As well as the SNG design capacity output of 56.7 PJ/a, the plant has a design capacity output of 0.7 PJ/a of electricity. However, all values in table 4.3, including efficiency, are based on SNG output alone.

4.5 High Calorific Value Gasification of Coal (Nuclear Heat Source)

To improve the economic utilization of coal resources, gasification processes with a low specific consumption of coal are desirable. In autothermal gasification processes the coal is not only used as raw material, but also to generate the process

energy. However, the reaction energy can be supplied as process steam or heat from a gas cooled high temperature nuclear reactor (HTR) to save approximately 30 to 40 % of the coal. Two characterizations of coal gasification systems using nuclear process heat were provided by Germany (Ref. 4.6). These were

- steam gasification of reactive hard coal followed by catalytic methanation of the raw gas to produce SNG;
- direct production of SNG by hydrogasification of brown coal.

Process energy for both gasification routes can be supplied by an advanced HTR with He-outlet temperatures above 850 °C. In the steam gasification process the high temperature heat required for the reaction is tranferred from the primary He-circuit of the HTR via the intermediate heat exchanger and secondary He-loop to the gasifier as steam. Coal is gasified by the steam yielding the products CO, CO_2, H_2 and CH_4. Conventional shift conversion, acid gas removal, and catalytic methanation processes are then used to transform the raw gas into SNG.

Brown coal can be gasified directly with hydrogen to give SNG. The hydrogen consumed in the process is produced by steam reforming of a fraction of the methane being generated in the hydrogasifier. The high temperature heat required for splitting methane in the steam reformer is provided by heat transfer from the primary He-circuit of the HTR.

These concepts are being investigated in the joint project "Prototype Plant for Nuclear Process Heat" (PNP) established in 1975 by the Bergbau-Forschung GmbH, GHT Gesellschaft für Hochtemperaturreaktor-Technik mbH, Hochtemperatur-Reaktorbau GmbH. Rheinische Braunkohlenwerke AG and the Kernforschungsanlage Jülich GmbH. The present planning of this project is based on a pebble bed HTR of 500 MW_{th} power output (PNP 500).

TABLE 4.4 - SNG from Coal (Nuclear Heat Source) - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	yrs
Germany - Catalytic gasification of hard coal	235	2000	145.2	85.6	85.6	72.2	19.0	0.59	0.86	20
Germany - Hydro gasification of brown coal	251	2000	162.4	85.6	85.6	75.6	18.06	0.59	0.44	20

Assessors

Walbeck, M. and Martinsen, D., KFA/STE, Postbox 1913,
5170 Jülich, FRG

Notes:

(1) All energy quantities based on NCV of fuels.

(2) Catalytic Gasification of Hard Coal

At full load, 100 % availability, energy inputs per year are

nuclear process heat	81 PJ
hard coal	154 PJ
	235 PJ

and energy outputs per year are

SNG (34.8 MJ/m^3 NCV)	150.7 PJ
electricity	18.9 PJ
	169.6 PJ

Design capacity is given in terms of energy input and all costs are expressed per unit of this capacity.
Variable O&M costs are double those of hydrogasification of brown coal presumably because of catalyst costs.

(3) Hydrogasification of Brown Coal

At full load, 100 % availability, energy inputs per year are

nuclear process heat	81 PJ
brown coal (NCV = 8.4 GJ/tonne)	170 PJ
	251 PJ

and energy outputs per year are

SNG (NCV = 35.9 MJ/m^3)	115.8 PJ
residual coke (NCV = 27.9 GJ/tonne)	70.2 PJ
electricity	3.7 PJ
	189.7 PJ

Design capacity is given in terms of energy input and all costs are expressed per unit of this capacity.

4.6 In Situ Gasification of Coal at Great Depth

The main advantages of coal gasification at great depth (800 m - 1500 m) compared with gasification at low depth (50 m - 150 m) are:

- higher pressures are allowed,
- higher power output per borehole (gasification speed is proportional to pressure),
- no gas leaks,
- no infiltration of ground water.

The first concept that was envisaged for the Belgian-German gasification project started in 1978 consisted of drilling vertical boreholes from the surface to a depth of 800 - 1500 m. Before the gasification takes place two boreholes are linked by the "retrocombustion technique" (see Figure 4.4): air is injected under high pressure (150 - 250 bar) in borehole No. 1, while a heat source is introduced at the bottom of borehole No. 2.. When enough air arrives at borehole No. 2 the coal is ignited and burns in the direction of borehole No. 1, opening a channel with a diameter of 0.3 to 0.9 m between the two boreholes (Ref. 4.7).

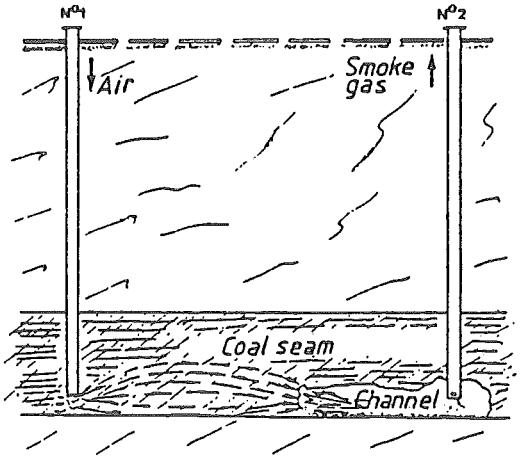


Figure 4.4: Connecting Two Boreholes by Retrocombustion (Source: Ref. 4.8)

By far the most important fraction of the gas cost is for the drilling, which costs about 15000 Belgian Francs/m ($\$_{80}$ 500/m). Therefore the boreholes should be kept as far apart from each other as possible. It is not yet clear whether distances between boreholes of 60 to 70 m, which are required to make the process economic, are achievable.

An alternative concept has recently been proposed which is called the "mixed method". It involves first mining a horizontal gallery (or the use of an old mine shaft) some 50 m below the gasification area - so that the high pressures can be withstood - and from there to drill vertical boreholes upwards for the injection of the gasifying media (Figure 4.5), while the gas recovery borehole is still drilled from the surface.

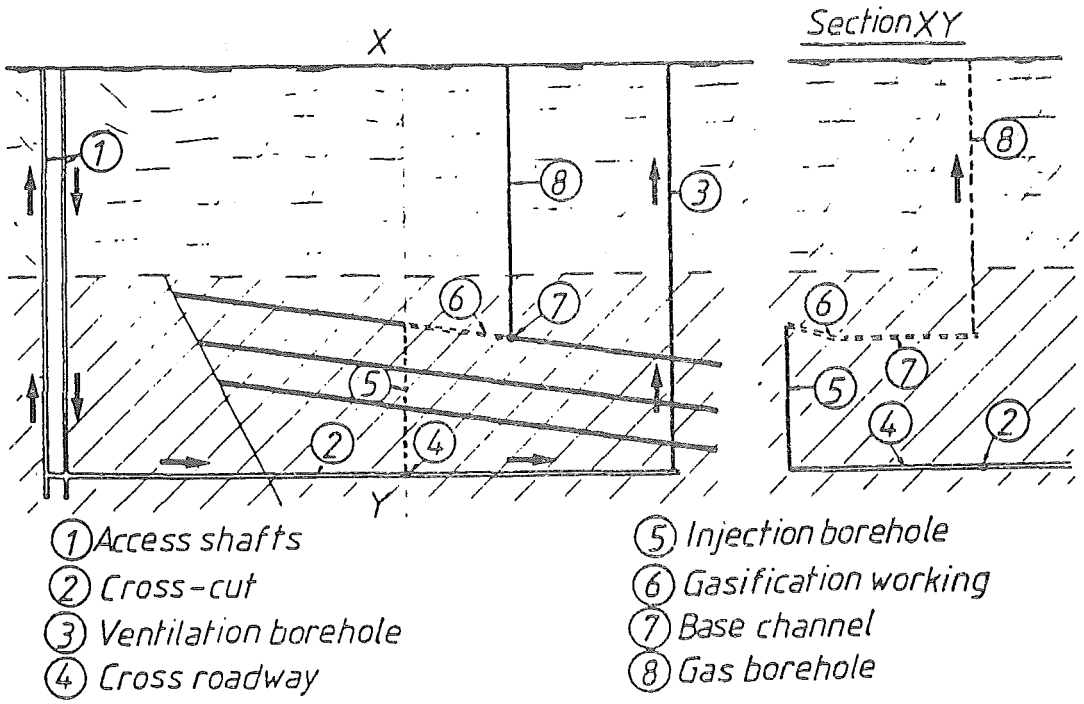


Figure 4.5: Layout of a Mixed-Method Working
(Source: Ref. 4.8)

This method, which is described in reference 4.8, looks economically more attractive because it reduces the drilling costs considerably. Moreover the cost estimates are more confident since the preparatory mining work is carried out using conventional means and since the number and cost of boreholes is of lesser importance in the total cost.

As far as the gasification media are concerned the best prospects seem to be offered by the use of both:

- O_2 and CO_2, introduced at ambient temperature behind the gasification front, and
- water, needed to cool down the gas produced, injected in carefully controlled quantities ahead of the gasification front.

As shown in Table 4.5, both the CO_2 and the steam participate in the gasification reactions, while the oxygen is used to provide heat for the gasification reactions by burning part of the coal.

TABLE 4.5 - Gasification Reactions with Steam and Carbon Dioxide

Gasification agent	Steam	Carbon dioxide
1. Gasification	$H_2O_{steam}+C = CO+H_2$	$CO_2+C = 2CO$
2. Cooling at the foot of each borehole	$CO+H_2+2H_2O_{liq} = CO+H_2+2H_2O_{steam}$	$2CO+2H_2O_{liq} = 2CO+2H_2O_{steam}$
3. Shift reaction	$CO+H_2+2H_2O_{steam} = CO_2+H_2O_{steam}+2H_2$	$2CO+2H_2O_{steam} = 2CO_2+2H_2$
4. Gas scrubbing	$CO_2+H_2O_{steam}+2H_2 = 2H_2+(CO_2+H_2O)\downarrow$	$2CO_2+2H_2 = 2H_2+(2CO_2)\downarrow$

(Source: Ref. 4.8)

Gasification could take place under a pressure of about 30 bar and at an equilibrium temperature of about 1000 °C. The use of 50 % CO_2 and 50 % O_2 would lead, after shift and scrubbing to approximately the following gas composition (Ref. 4.9):

CO_2	2 %
CO	23 %
H_2	72 %
CH_4	3 %

The cost estimate provided in the characterization is still rough and should be considered as an order of magnitude. It was taken from reference 4.8. As for conventional mining it is rather tricky to isolate investment costs and to identify associated lifetimes. Therefore all costs were expressed as variable costs in this assessment and were included under "Variable O&M Costs". The exchange rate used is 1 Belgian Franc = $\$_{80}$ 29.2 or 1 Pound Sterling = $\$_{80}$ 2.74.

The preparatory mining costs are based on those of the Belgian Campine basin, which are among the highest in Europe. They are conservative since in reality smaller diameters would be needed for the shafts and since more coal could be recovered (coal in seams that are too thin for conventional mining).

Status of R&D

The development programme for the Belgian-German gasification experiment at Thulin (Belgium) is given in Table 4.6.

Four boreholes were drilled at a depth of 80 m and permeability measurements began in January 1981. First linking experiments with retocombustion should start in September 1981 and first gasification is scheduled for early 1982.

Current spending for the project amounts to about 5 million $\$_{80}$ per year.

TABLE 4.6 - Schedule for the Thulin Trials

Phase 1 three years 1979 - 1982	Erection of surface installations Drilling four boreholes to a depth of 880 metres Linking-up boreholes 35 metres apart Gasification : small faces; air/steam
Phase 2 two years 1982 - 1983	Drilling three new boreholes to a depth of 880 metres Linking-up boreholes 35 metres apart Gasification : longwall; oxygen/steam
Phase 3 two years 1984 - 1985	Deepening six boreholes to a depth of 980 metres Linking-up the boreholes Gasification of a second seam : longwall

(Source: Ref. 4.9)

The Belgian characterization, summarized below in Table 4.7, is for in situ gasification of coal at ~ 1000 m depth using the "mixed" method, for the production of a synthesis gas with a NCV of about 12 MJ/m^3.

TABLE 4.7 - In Situ Gasification of Coal - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%			$/GJ	
Belgium	23.6		18.9	80		60	→	→	4.75	

Assessor

Altdorfer, F., Services Programmation de la Politique Scientifique, Rue de la Science 8, B-1040 Brussels, Belgium

Notes:

(1) Design capacity value if for gas output

(2) Total capital cost and fixed O&M cost are included under the variable O&M cost heading. Breakdown is

	$/GJ
preparatory mining	2.21
bore holes and piping	1.11
preparation of gasifying media and gas treatment	1.43
	4.75

4.7 Methanol from Coal and Biomass

Currently, methanol is produced mainly from natural gas, but sometimes from LPG or naphtha, and fulfils the demand for methanol as a chemical rather than as a fuel. If methanol is to be produced in large quantities as a fuel, coal and possibly biomass can be expected to gain increasing importance as feedstocks.

Methanol could be used as a sulphur free boiler or gas turbine fuel or used to augment transport fuels in a number of ways (Ref. 4.11), namely:

- as an extender for gasoline (the 15 % methanol blend is called M15)
- by conversion to gasoline in the Mobil MTG process (see Section 4.8)
- by conversion to other gasoline extenders such as methyl tertiary butyl ether (MTBE)
- by using straight methanol in specifically designed engines.

Nearly all methanol is made from synthesis gas (hydrogen and carbon monoxide) using one of the three processes currently marketed: the ICI low pressure process, the Lurgi process and the Vulcan-Cincinnati process. Processes used are thoroughly established and closely integrated in production units. Overall thermal efficiency of today's processes is of the order of 65 % and little potential for further improvement in efficiency is seen.

Coal gasification processes likely to be used for the manufacture of methanol will essentially deliver a raw synthesis gas (see section 4.2). Acid gas removal sulphur recovery and gas cooling stages are required for gas cleanup/cooling before passing through to the methanol synthesis loop. A water-gas shift conversion may be required to increase the hydrogen content of the raw gas. For example, in the ICI process which employs copper catalysts to convert CO and H_2 to methanol a H_2:CO ratio of 2.0 is desirable (Ref. 4.12). Other sources (Ref. 4.13) indicate a higher ratio of 2.6.

Technical options available (Ref. 4.13) are to produce only methanol as the major output or to co-produce methanol and SNG. In the first option all the methane produced in the gasifiers is reformed to additional synthesis gas which is converted to methanol. In the co-production option unconverted synthesis gas from the methanol synthesis reactor is methanated and together with primary methane from the gasifier, is marketed as SNG.

The earliest method of manufacture of methanol was by the destructive distillation of hardwood - and indeed methanol was originally called 'wood alcohol'. It would be feasible to resurrect and to improve old processes to convert wood, wood waste, wheat, or straw to synthesis gas and thence to methanol. It has been argued that such processes would be more economically and thermally efficient than conversion by biological processes to ethanol (Ref. 4.14).

4.7.1 Methanol from Coal and Biomass - Characterization Summary

Four characterizations were submitted for methanol producing processes and these are summarized in Table 4.8. Two were for processes using coal as feedstock (U.S.A. and Germany) and two were for processes using peat and/or biomass (Sweden and U.K.).

TABLE 4.8 - Methanol from Coal or Biomass - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
U.S.A. Methanol from Coal	85	1991	76.5	90	90	57	32.95	1.09	0.40	30
Germany Methanol and SNG from Hard Coal	27.8		23.6	85	85	62	14.5	1.03	0.16	20
Sweden Methanol from Peat and Biomass	10.9	1990	9.4		86.5	50	33.9	2.48	0.25	20
U.K. Methanol from Wood	4.1	2000	3.7	90	90	55	20.7	0.57	0.63	20

Assessors

U.S.A.:- Bhagat, N., Brookhaven National Laboratory, Upton, NY 11973.

Germany:- Eickhoff, H.G., KFA/STE, Postfach 1913, 5170 Jülich.

Sweden:- Brandberg, A., Swedish Methanol Dev. Co., Stockholm.

U.K.:- Ward, A.V., ETSU, Harwell.

Notes

(1) All energy quantities based on NCV of fuels.

(2) Methanol from Coal - U.S.A.

Coal is gasified to produce synthesis gas which is converted with the aid of catalysts to yield methanol. Example: Fischer-Tropsch process.
The assessor provided confidence limits on some items in Table 4.8 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
First Commercial Service Year	-	1991	1990	1995
Overall Efficiency (average load)	%	57	52	62
Total Capital Cost	$/GJ/a	32.95	28.9	40.5
Fixed O&M Cost	$/GJ/a	1.09	0.90	1.40
Variable O&M Cost	$/GJ	0.40	0.35	0.55

(3) Methanol and SNG from Hard Coal - Germany

Energy outputs at full load are 17.9 PJ/yr methanol and 9.9 PJ/yr SNG. Total capital cost is $14.5/GJ/a based on both outputs or $22.5/GJ/a based on methanol output alone. These values seem unusually low.

Fixed O&M cost is broken down as follows:-

	$/GJ/a
Repairs (3 %/a)	0.435
Insurance (0.5 %/a), taxes (2.6 %/a)	0.450
Labour	0.141
	1.026

Variable O&M costs are for catalysts and water.

(4) Methanol from Peat and Biomass - Sweden

The plant description is as follows:

Peat, wood and similar biomasses are dried and gasified with oxygen and steam vapour under moderate pressure (10 bar). The hot raw gases are cooled for heat recovery and purified from dust, saturated with steam and shifted over a catalyst in several parallel trains. Combined shifted gases are compressed, purified from sulphur compounds and excess CO_2, synthesized over a catalyst to methanol which is purified by distillation in a single train. A size of 1500 tonnes/day of methanol output was chosen for economy of scale.

Fixed O&M costs which seem high compared with other characterizations are broken down as follows:-

	$ x 10^6	
Labour	6	
Maintenance material	8	
Overheads	5	
Insurance, property taxes	8	
	27	for design capacity of 10.9 PJ/yr output

Variable O&M Costs are for chemicals, catalysts, and utilities with the exception of electricity which is generated in the plant.

(5) Methanol from Wood - U.K.

In this process the feedstock is heated in a controlled atmosphere of steam which allows more efficient conversion to synthesis gas than in the alternative processes of pyrolysis (destructive distillation at or near atmospheric pressure in the absence of air or oxygen) or oxygen gasification.
Methanol is then produced by catalytic conversion of the synthesis gas.
The plant produces 500 tonne/day of methanol and requires about 900 dry tonnes/day of coppiced timber (assuming 21 GJ/dry tonne). If sufficient land surrounding this methanol plant was totally afforested, this would represent approximately 50,000 hectares (circle diameter 15 miles). The same area of land could alternatively produce enough wood to make about 300 tonnes of SNG per day (assuming yields of 7 dry tonnes/ha/a.
Operating and maintenance costs were taken to be about 5 % of capital costs and assigned equally between variable and fixed costs.

4.8 Gasoline from Coal Derived Methanol

Methanol (and other alcohols) can be converted to high quality aromatic-type gasoline by a zeolite catalytic process recently developed by Mobil (Ref. 4.16). The Mobil MTG (Methanol-to-Gasoline) process has a thermal efficiency of about 90 % but the efficiency of this route to gasoline is penalised by the lower efficiencies of the combined gasification-methanol synthesis stages that precede it (section 4.7). Two characterizations were received describing this process. These are summarized in Table 4.9.

4.9 - Gasoline from Coal Derived Methanol
- Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
U.S.A.	85	1992	76.5	90	90	52	37.0	1.28	0.48	30
KFA Operating Agent from IEA/EAS sources	136.6		116.1	85	85	41.8	26.9	1.24	0.62	20

Assessors

U.S.A.:- Bhagat, N., Brookhaven National Laboratory, Upton, NY 11973

KFA Operating Agent:- Maher, K., KFA/STE Jülich, Postbox 1913, D-5170 Jülich, FRG

Notes:

(1) All energy quantities based on NCV of fuels.

(2) U.S.A.

The assessor provided confidence limits on some items in Table 4.9 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
First Commercial Year	-	1992	1990	1996
Overall Efficiency (average load)	%	52	47	57
Total Capital Cost	$/GJ/a	37.0	32.37	46.24
Fixed O&M Cost	$/GJ/a	1.28	1.0	1.6
Variable O&M	$/GJ	0.48	0.35	0.60

At full load the process produces 76.5 PJ/a of gasoline and 8.5 PJ/a of LPG.

(3) KFA Operating Agent from IEA/EAS Sources (Ref. 4.13)

The plant description is as follows:-
Dry-ash Lurgi gasification of Illinois No. 6 bituminous coal. All of the methane produced in the Mark IV gasifiers is reformed (autothermal, catalytic) to additional synthesis gas which is converted to methanol in a low pressure reactor. Methanol is converted to gasoline and other products over a fixed bed of zeolite catalyst. Naphtha and tars/oil from gasifiers upgraded to lighter products, some of which are blended with the gasoline product.

Full load (100 % availability) input is 327 PJ/a of coal with a NCV on an "as received" basis of 25.87 GJ/tonne. Full load outputs are:-

	PJ/a
Gasoline	112.7
Diesel Oil	8.4
Butane (LPG)	9.4
Propane (LPG)	6.0
	136.6

The efficiency of the process is sensitive to coal type. For example, Reference 4.13 gives the efficiency (GCV basis) as 43.5 % for Illinois No. 6 bituminous coal feedstock and 50 % for Australian Wandoan sub-bituminous coal feedstock.

Construction cost breakdown is:-

	$/GJ/a
Synthesis gas production	8.2
Methanol synthesis	2.6
MTG conversion	2.1
Offsites and utilities	7.6
Contingency (15 %)	3.1
	23.6

Fixed O&M cost breakdown is:-

	$\$_{80} \times 10^6$
Operating labour	29.9
Maintenance labour	56.0
Insurance, local taxes	84.0
	169.9

Variable O&M cost breakdown is:-

	$\$_{80} \times 10^6$
Water	5.6
Catalysts and chemicals	18.4
Maintenance materials	47.6
	71.6

4.9 Indirect Liquefaction of Coal; Fischer-Tropsch

In this route, which is to be distinguished from direct liquefaction (section 4.10), coal is first gasified to produce a hydrogen and carbon monoxide mixture (synthesis gas). These gases are then re-combined with the aid of catalysts to produce liquid fuels. At present, only two re-combination processes are practicable. These are methanol synthesis (section 4.7) and Fischer-Tropsch synthesis which is described in Ref. 4.17 as follows.

The principal Fischer-Tropsch reaction is

$$m(CO + 2H_2) \longrightarrow (- CH_2 -)_m + m\ H_2\ O$$

The products are primarily straight chain hydrocarbons from methane to waxes and include paraffins, olefins, aromatics and alcohols. The product stream from a Fischer-Tropsch plant is a mixture of such hydrocarbons and can be regarded as a sweet semi-refined crude. The range of products depends on reaction temperature, catalyst, and synthesis gas composition.

There are two schemes under which the Fischer-Tropsch synthesis is being operated industrially:

(a) In a tubular reactor, filled with a precipitated catalyst and cooled with boiling water, under quasi-isothermal conditions. This is the Ruhrchemie-LURGI system (commonly called ARGE).

(b) In a loop-type reactor, where a dust cloud of fused catalyst is circulated, under adiabatic conditions and with interstage cooling. This is the Synthol system originally developed in the U.S. and then further developed by SASOL.

The products from scheme (a) are essentially straight chained hydrocarbons, with the mean molecular weight being somewhat higher than products from scheme (b), i.e. with a shift to higher boiling fractions and waxes. The yield of oxygen containing compounds is rather small.

In contrast, scheme (b) produces compounds with a lower mean molecular weight, more oxygen containing products and the fraction of iso-paraffins in the higher boiling range is greater as well.

Since 1955, both synthesis methods have been successfully operated by SASOL at their Sasolburg, South Africa, facilities.

The scale-up of the Synthol process from the U.S. pilot plant to the commercial SASOL plant initially caused difficulties. The ARGE system performed from the start in accordance with the design expectations. However, SASOL have managed to debug the Synthol system.

The ARGE system produces primarily kerosene, diesel fuel, and waxes. The Synthol system produces primarily LPG and gasoline. The differences are due to the gas composition, operating temperature, pressure, and catalyst type and are not due to the type of reactor design (tubular versus entrained suspension reactor). However, each reactor type is most suitable for the conditions selected. By varying the operating conditions, the

product range can be changed. The Synthol system, for instance, could be operated to produce more methane and LPG if the market conditions so dictated.

The SASOL plant is a major demonstration of the Lurgi Dry Ash Pressure Gasification process. In addition, it represented the first coalgas application for the Lurgi Rectisol process for sulphur and CO_2 removal.

A new plant, SASOL II is in start-up and SASOL III is in construction. SASOL II has five times the capacity of the original Sasolburg facility. The gasifiers used are the largest commercial units built: the Mark IV. The first three Mark IV gasifiers were used in the latest expansion of the existing SASOL plant.

Since LPG and gasoline are the major desired products, only the Synthol Fischer-Tropsch system will be used for SASOL II. The plant will use seven scaled-up Synthol reactors to produce a quantity of liquid products variously reported (Ref. 4.13) as being between 35,000 to 60,000 barrels per day.

The new SASOL II complex also includes Lurgi's Authothermal methane reforming process, an ethylene plant, a Lurgi tar distillation plant, a combined Lurgi phenols and ammonia recovery plant, and a products refinery including light olefin polymerization and hydrogenation, isomerization, and a Distillate Selective Cracking unit. SASOL II has 36 gasifiers and is probably the largest project ever undertaken in the chemical, petrochemical or refinery class of projects.

Technical options available are to use methane reforming and produce only liquid products or to co-produce liquid products and SNG. The thermal efficiency of the latter option is significantly higher than the former.

4.9.1 Fischer-Tropsch Liquefaction of Coal - Characterization Summary

Two characterizations were submitted describing the Fischer-Tropsch process. One (Australia) was for a producing only liquids and one (Germany) was for co-production of SNG and liquids. The characterizations are summarized in Table 4.10.

TABLE 4.10 - Fischer-Tropsch Liquefaction of Coal - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Australia (liquid products only)	137	1988	116	85	85	40	37.5	2.6	←	25
Germany (SNG and liquid products)	176		150	85	85	55	20.4	1.45	0.51	20

Assessors

Australia:- Department of National Development and Energy, CAGA Centre, Akuna St., Canberra City, ACT, 260

Germany:- Eickhoff, H.G., KFA/STE, Postfach 1913, D-5170 Jülich, FRG

Notes:

(1) All energy quantities based on NCV of fuels.

(2) Australia (Refs. 4.11, 4.18)

Process described simply as "SASOL fixed bed operation". Energy input at full load is 350 PJ/a bituminous coal. Energy outputs are

	PJ/a
Gasoline	40
Diesel oil	27
Heavy oil	70
	137

Variable O&M costs included under fixed O&M cost.

The assessor provided confidence limits on some items in Table 4.10 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
First Commercial Year	-	1988	1987	1990
Total Capital Cost	$/GJ/a	37.5	33	42
Total O&M Cost	$/GJ/a	2.6	1.1	5.1

(3) Germany

Energy input at full load is 320 PJ/a hard coal. Energy outputs at full load are

	PJ/a
SNG	93.2
LPG	7.9
Naphtha	45.0
Diesel oil	24.2
Fuel oil	5.7
	176.0

High value for efficiency results from co-production of SNG and liquid products. Fixed O&M cost breakdown is

	$/GJ/a
Repairs (3 %)	0.612
Insurance (0.5 %), taxes (2.6 %)	0.632
Labour	0.209
	1.453

Variable O&M costs are for catalysts and water.
Variation between capital costs for the USA and German characterizations cannot be simply explained in terms of the difference between methane reforming and co-production configurations.

4.10 Direct Liquefaction of Coal

In this route, crushed coal is slurried or dissolved in a process-derived oil and reacted directly with hydrogen at high temperature and pressure. The three leading direct coal liquefaction processes are:

(i) Direct hydrogenation: Coal slurried in a process-derived oil is reacted with hydrogen. A typical process is the H-Coal project of Hydrocarbon Research Inc. in the U.S.A.

(ii) Donor solvent extraction: Coal is dissolved in a catalytically hydrogenated process-derived oil and then treated by further hydrogenation. A typical process is the EXXON Donor Solvent method.

(iii) Solvent extraction process: Coal is dissolved in a recycled process oil and then reacted with hydrogen without catalysts. A typical process is Solvent Refined Coal (SRC-II).

Each of these approaches are discussed in more detail in the following three subsections. The essential configuration differences between the three different approaches are shown in Figure 4.6.

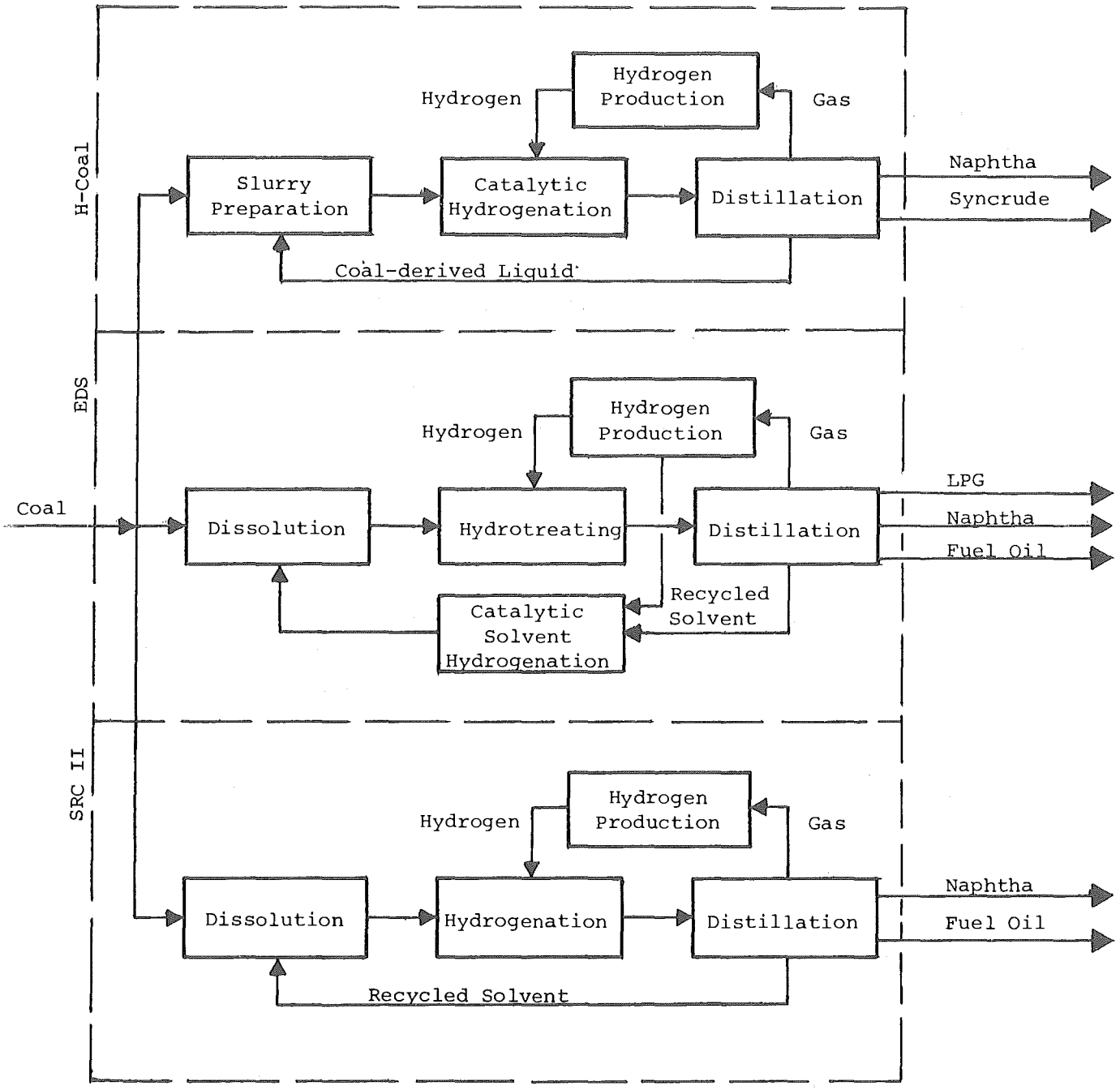


Figure 4.6: Alternative Methods for Direct Liquefaction of Coal

Source: DungLe, Australian Atomic Energy Commission, private communication

4.10.1 Direct Hydrogenation: H-Coal^R Process

Reference 4.19 describes this technology as follows. The H-Coal^R process is primarily a liquefaction system but does produce significant quantities of SNG and LPG. Briefly, coal is cleaned, dried, pulverized and slurried with process-derived oil in the preparation section. It is then pumped to reactor pressure, mixed with hydrogen, heated, and charged to the reactor. There, the coal, recycle oil and hydrogen react in the presence of a catalyst at pressures up to 3,500 psig and temperatures to 850 °F. Depending on the severity selected, the product slate can be an all distillate material. After leaving the reactor, the liquid effluent is treated to provide a low-solids recycle oil which is used to slurry the coal. The balance of the liquid is fractionated into distillate products and ash-containing residuum. The heavy ends can be further treated to recover additional ash-free hydrocarbons or used as feed to a hydrogen plant.

The concept involves a catalyst bed that is kept in an expanded or ebullated state by charging the feed and additional recycle oil to the bottom of the reactor. The products, including unreacted coal and ash, flow through the catalyst and are removed from the reactor at a point above the catalyst bed. An external separator removes gaseous products and recycle hydrogen from the liquid.

At the present time, a U.S.A. consortium of industry and government is funding an H-Coal^R pilot plant constructed at Catlettsburg, Kentucky which has operated since the beginning of 1981 processing 250 t/d of coal to produce distillate oil and 600 t/d for heavy boiler oil.

4.10.2 Donor Solvent Extraction: Exxon Donor Solvent (EDS) Process

Reference 4.11 describes this method as follows.

Exxon has been developing the Exxon donor solvent process since 1966, firstly in a 1/2 t/d process demonstration unit (PDU), then in a 1 t/d PDU, and more recently in a 250 t/d pilot plant.

The 250 t/d pilot plant at Baytown, Texas, has recently commenced operation. Total cost is estimated at US $240 million, including a three-year operation period which will initially test Eastern US coal, followed by Western US sub-bituminous coal and possibly lignite. The plant will produce 600 bbl/d oil equivalent.

The process essentially consists of coal drying, grinding and slurrying with hydrogenated recycle solvent (or donor solvent) slurry heating and reaction with hydrogen in a non-catalytic tubular reactor at 430-470 °C and 10-14 MPa, distillation of reactor product, and coking of vacuum distillation bottoms.

The product slate consists of a range of light and heavy hydrocarbons, including LPG, Naphtha and fuel oil.

Critical processing steps are adaptations of petroleum refining technology and are therefore simple; e.g. coal liquids, rather than coal, are catalytically hydrogenated, thus avoiding catalyst contact with coal; solids-liquids separation is by vacuum distillation rather than the problematic mechanical separation; use of hydrogenated recycle solvent allows a significant improvement in process operability and yields a higher range of distillation product.

Methane produced during liquefaction can be solid as SNG or reformed to produce hydrogen for the process.

In order to compare the economics of EDS with indirect liquefaction processes which produce motor fuels it is necessary to include the cost of upgrading EDS coal liquids to light products. A typical upgrading plant is described in Ref. 4.13 as including hydrotreating facilities for removal of nitrogen, sulphur and oxygen from the naphtha prior to reforming and

hydrocracking for the gas oil fraction which produces a naphtha feed for the reforming operation. Both the hydrotreated naphtha and the hydrocrackate are then fed to the reformer to produce gasoline of about 93 RON. Part of the hydrogen for these steps is produced during reforming and the remainder is produced by the gasifiers in the EDS plant. Some SNG and LPG are produced during upgrading and are included as plant products after deducting the fuel requirements for the upgrading plant.

4.10.3 Solvent Extraction Process: SRC-II (Refs. 4.2, 4.11, 4.20)

Solvent refined coal is defined to be the organic material in coal that has undergone dissolution or suspension in a solvent (usually at T 375 °C). During the processing most organic material in the coal has been removed; also the solvent has been at least partially removed. SRC-I product is a solid at room temperature, the softening point (T) depending on the degree of solvent removal.

The Pittsburgh and Midway Coal Mining Co., a subsidiary of Gulf Oil Corporation, has been studying the solvent refining process since the early 1960s. Initial emphasis was on production of solid solvent refined coal (SRC-I) and the process was modified to incorporate liquid production in the mid 1970s. So far, development has been mainly carried out in a 45 t/d pilot plant at Tacoma, Washington.

In the SRC-I process coal is ground, dried to 3 per cent moisture and slurried with solvent and hydrogen before introduction into the preheater. The mixture is reacted in the dissolver at up to 425 °C and 2000 psi where over 90 per cent of the organic portion of the coal is dissolved or suspended. Chemical reactions occuring under such conditions include 1) thermal and catalytic bond rupture (utilizing minerals in the coal), 2) hydrogenation of reactive fragments from 1), 3) solvent dissociation, dehydrogenation and isomerization, and 4) removal of oxygen and sulphur from the coal and inorganic materials associated with the coal. This latter step usually

reduces the concentration of sulphur to 10 to 15 per cent of its original concentration in the coal. Since minerals are not soluble in the organic solvent they may be removed by filtration, centrifugation or other methods. The extract is flash distilled to separate solvent.

The most difficult problems associated with SRC-I production concern the liquid-solids separation step. Because of these difficulties, development of SRC-II was pursued by Gulf. The basic idea behind this development was to produce a distillable liquid product. This would eliminate the need for filters, centrifuges and other physical separation methods. The penalty for producing a distillate product is approximately a doubling of the hydrogen required in the process.

A consortium, headed by Gulf Oil Corporation and including Ruhrkohle and Japanese industry and sponsored by the US, FRG and Japanese governments intended to construct a 6000 t/d SRC-II plant near Morgan town, Virginia. Estimated production of oil and gas was 20,000 bbl/d equivalent. However, in June 1981 the three governments announced its abandonment for reasons other than technical feasibility.

4.10.4 Direct Liquefaction of Coal - Characterization Summary

TABLE 4.11 - Direct Liquefaction of Coal - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Australia (brown coal hydrogenation)	140	1996	119	85	85	39	36.7	2.6	-	25
Japan (hard coal direct liquefaction)	168	1990	143	85	90	70	16.9	1.2	0.33	20
U.K. (hard coal liquid solvent extraction)	68.4		61.6	90	90	68.6	23	0.9	0.02	
U.S.A. (coal direct liquefaction, e.g. SRC, EDS, H-coal)	85	1995	76.5	90	90	68	27.2	0.9	0.33	30

Four characterizations were received for direct liquefaction processes. These are summarized in Table 4.11.

Assessors

Australia:- Department of National Development and Energy, CAGA Centre, Akuna St., Canberra City, ACT, 2601

Japan:- Koyama, S., Kashihara, T., and Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki

U.K.:- Ward, A.V., ETSU, Harwell

U.S.A.:- Bhagat, N., Brookhaven National Laboratory, Upton, NY 11973

Notes:

(1) All energy quantities are based on NCV of fuels. Design capacities and all specific costs are expressed in terms of energy outputs of plants.

(2) Brown Coal Hydrogenation - Australia

The assessment obtained general brown coal hydrogenation information from the FRG/Australia coal-to-oil feasibility study and is therefore Bergius hydrogenation. The plant is assumed to include a secondary refinery-type plant to process raw output liquids to refined products such as gasoline, diesel oil etc.

The efficiency of the brown coal liquefaction process (39 %) is low compared with the hard coal direct liquefaction process summarized in Table 4.11. On a dry coal basis brown coal and hard coal can be liqui-

fied with roughly similar efficiencies. However, to produce 1 tonne of dry brown coal with a GCV of 27 GJ/te, 3 tonne of "wet" brown coal with a GCV of about 9 GJ/te must be used together with another 2 tonne to provide process heat for coal drying. In addition, the secondary refinery-type plant has an efficiency of about 85 % which is slightly lower than the 90 % of a normal oil refinery due to the much heavier fraction of the raw coal liquids. Thus, if the efficiency of the basic brown coal hydrogenation process is 60 %, overall efficiency is

60 % x 3/4 x 0.85 = 39 % (Dung Le, AAEC, private communication)

Investment costs for brown coal liquefaction plants are higher than corresponding hard coal plants due to the costs of coal drying and handling larger input volumes. These costs are independent of the basic liquefaction route and are typically 10 % of the total process investment. The operating and maintenance cost, which includes fixed and variable items under the fixed O&M heading in Table 4.11, is estimated as being 8 % of investment cost.

Product slate at 100 % availability is

gasoline	94 PJ/a
diesel oil	46 PJ/a

The assessor provided confidence limits on some items in Table 4.11 as follows:

Item	Unit	Median Value	10 % Probability of Being	
			Less Than	Greater Than
Total Capital	$/GJ/a	36.7	33	41
Total O&M Cost	$/GJ/a	2.6	1.1	5.1

(3) Hard Coal Direct Liquefaction - Japan

The process is a characterization of a plant constructed in foreign countries which liquifies hard coal by the direct

hydrogenation method. Output liquids are naphtha, light oil and heavy oil.

(4) Hard Coal Liquid Solvent Extraction - U.K.

The process described in this characterization is the U.K. National Coal Board (NCB) Liquid Solvent Extraction technology. The NCB has provided the assessor with the following process description.
The key feature of the NCB process is that removal of mineral matter precedes hydrogenation. The overall process can then be optimised for the production of premium distillate products (LPG, non-leaded high-octance gasoline, jet fuel and diesel fuel). Methane produced may be used as plant fuel, as a source of process hydrogen or sold as SNG. Heavier fractions are utilised in the process, but the product slate can be readily altered to include some heavier materials (eg. refined pitch or electrode coke) should they acquire premium values. The high selectivity and flexibility result from the process being conducted in two stages. A "clean" coal extract produced in the first stage is hydrocracked, and the products refined, in the second stage. Removal of potential catalyst deactivating materials in the first stage ensures that a highly selective catalyst can be employed in the hydrocracking operation.

A high-boiling, coal-derived solvent is employed to extract the coal and is used as the vehicle to carry the extract through the hydrocracking operation. This solvent contains components capable of transferring hydrogen to the coal during the pyrolysis/solution process and this permits depths of extraction up to 90 per cent of the coal substance. The hydrogen donor capability of the solvent is regenerated as it passes through the hydrocracker. Because of the important role played by the solvent, the overall process is referred to as the Liquid Solvent Extraction (LSE) process, to distinguish it from other processes currently being developed.

The coal extracts can be hydrocracked to yield naphtha and middle distillate as principal products under conditions no more severe than those employed in conventional oil refining. When refined pitch (or electrode coke) is a co-product, hydrocracking conditions are even less exacting.

(5) Coal Direct Liquefaction - U.S.A.

The U.S.A. characterization is a generic description of liquefaction of coal by a direct process such as SRC, Exxon Donor Solvent process, or H-coal. Crushed coal is slurried in a process-derived solvent and reacted directly with hydrogen in high temperature and pressure conditions. The yields and characteristics of the products depend on reactor conditions and degree of hydrogenation.

The assessor provided confidence limits on some items in Table 4.11 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
Overall Efficiency (average load)	%	68	62	74
Total Capital Cost	$/GJ/a	27.2	24.3	34.7
Fixed O&M Cost	$/GJ/a	0.90	0.8	1.3
Variable O&M Cost	$/GJ/a	0.33	0.30	0.50

4.11 Ethanol From Biomass

The properties of fuel ethanol and the methods for its production are described below with extracts from Ref. 4.11.

Ethanol can be produced by microbial fermentation of sugars and sugar polymers such as starch or cellulose. Starch and cellulose require chemical or enzymatic hydrolysis for fermentation to proceed. This is a simple step for starch, but much more difficult for cellulose. A wide range of crops can be used as feedstock, including sugar cane, cereal grains, cassava, sweet sorghum, and sugar of fodder beet. The ethanol is produced as a dilute solution in water and concentrated by distillation.

Ethanol's attraction lies in the fact that it can be produced efficiently by plants smaller than those required for economic production of, say, methanol or oil from coal. As a fuel extender it is therefore capable of being implemented comparatively rapidly and avoids the lead times and investment problems associated with larger scale synthetic fuel plants. In addition, the technology, though capable of improvement, is old and well understood. However, there is some concern as to whether production of ethanol feedstocks can compete with alternative uses for the land available.

Ethanol is a high octane fuel which can be used as a substitute or extender for gasoline in spark ignition engines. It is not, however, a ready substitute for distillate. Owing to its low cetane number and poor compression ignition properties, it cannot be used as a straight diesel fuel without major engine modification. It can be used as a distillate extender in blends, emulsions, or with dual fuel injections systems, but it is not yet proven that its fuel performance is satisfactory.

Many of the arguments applying to methanol apply also to ethanol. In general, ethanol - perhaps because it is the second member of the series and thus more like the hydrocarbons and

less like water - is the easier of the two alcohols to integrate into the transport fuel market and it raises fewer difficulties in distribution, storage and use.
There are many similarities between ethanol and methanol as substitute fuels, although ethanol is less poisonous than methanol and causes less deterioration of some materials used in present vehicles. Both can be used as extenders to gasoline; both can be used as pure fuels in spark ignition engines; and both can be converted via the Mobil process to gasoline.

Ethanol has little more than half the energy content (59 %) of gasoline, but overseas engine tests indicate that the fuel consumption may be better than would be anticipated from the energy content.

Like methanol, ethanol has a higher heat of vaporisation than gasoline, giving rise to cold starting problems for the straight fuel. Cold starting does not appear to be a problem for blends of up to 20 % ethanol.

Ethanol-gasoline mixtures tend to separate into two layers at low temperatures and in the presence of moisture (phase separation), but water tolerance is higher than for methanol-gasoline blends. As in the case of methanol, the addition of ethanol to gasoline increases the vapour pressure, but the effect is less pronounced, and at least for 10 % blends the effect on vapour lock is negligible.

A characterization was received from Australia (Table 4.12) describing the production of ethanol from sugar cane juice using conventional (1981) technology. It is proposed that crushed cane stalks (bagasse) would be used as the process fuel.

TABLE 4.12 - Ethanol From Biomass - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Australia (ethanol from sugar cane juice)	2.76		2.76	100	100	36	30.2	2.19	2.3	20

Assessor:

Australia: - Department of National Development and Energy, CAGA Centre, Akuna St., Canberra City, 2601, ACT.

Notes:

(1) Design Capacity. The capacity valve corresponds to an ethanol production of 120 x 10^6 litres/a. A gross calorific value (GCV) of 23 MJ/L was used for ethanol. The net calorific value (NCV) of ethanol is 20.8 MJ/L (Ref. 4.14). Characterization values have been left in GCV form because of difficulties in recalculating into NCV form the energy inputs which include growing, harvesting and cane transport components.

(2) First Commercial Year. The plant described is only a proposal and no definite dates can be assigned, but the earliest possible date would be 1986.

(3) Overall Efficiency. Calculated on GCV basis as follows.

Energy Inputs (PJ/a)	Median Value	10 % Probability of Being-	
		Less Than	Greater Than
Cane as harvested (1.41 M tonnes/a)	6.88	-	-
Growing and harvesting	0.49	0.44	0.55
Transport of cane for processing	0.061	0.050	0.10
Processing	0.174	0.12	0.25
Transport of ethanol to refinery	0.025	0.02	0.03
	7.63		
Energy Outputs (PJ/a)			
Ethanol	2.76		

(4) Costs. The assessor provided confidence limits on some items in Table 4.12 as follows:

Item	Unit	Median Value	10 % Probability of Being-	
			Less Than	Greater Than
Total Capital Cost	$/GJ/a	30.2	24.8	33.1
Fixed O&M Cost	$/GJ/a	2.19	2.0	2.4
Variable O&M Cost Including Sugar-cane Cost	$/GJ	12.5	11.5	21.1
Variable O&M Not Including Sugar-cane Cost	$/GJ	2.3	-	-

Median value of sugar cane feedstock cost assumed was $ 20/ tonne.

4.12 Biogas From Manure

A characterization was received from Denmark (Table. 4.13) describing production for local use of methane-rich biogas from manure derived from a large farm population of approximately 700 animals. The data are for a system already operating at Fiskebakegard, Grasten Landbrugsskole, Denmark. It is a continuous feed biogas system for fermentation of manure under anaerobic conditions using a completely mixed two step process requiring two series connected reactors each of 180 m^3 volume.

A good deal of the gas (100 m^3/day out of total production of 370 m^3/day) is used for heating the reactor. The system requires electricity for large pumps etc. The gas produced contains approximately 65 % CH_4. It is used in local furnaces for process heat and for heating of buildings (i.e. local use).

TABLE 4.13 Biogas From Manure - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Full Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	GJ/a		GJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Denmark	2300	1980	2070	66	90	29	42	1.85	←	15

Assesor:

Denmark: - Christensen, C.J., Riso, Roskilde

Notes:

(1) Design Capacity. Measurements over only 6 months indicate a production of 295 - 370 m^3/day of biogas. Design capacity has been calculated from measured maximum daily production of 370 m^3/day less 100 m^3/day internal use. The biogas is approximately 65 % methane (with NCV of 36 MJ/m^3) and the remaining 35 % is mostly CO_2.

(2) First Commercial Year. The assessor has entered the first year of regular operation of the experimental system under this heading, but has stated that the system is definitely not yet commercial.

(3) Maximum Annual Energy Output. 2 300 GJ/a x o.q (availability factor) = 2 070 GJ/a

(4) Overall Efficiency (Full Load). Input is delivered from feedstock of 100 dairy cows and 600 pigs producing 15 m^3/day wet manure plus 840 - 1080 kg/day dry organic material (straw). Very little data is available for converting this into energy input. There is also an electricity input of 160 GJ/a. An efficiency of 40 % claimed for the process is based on gross output. An efficiency based on net output is given by

$$\frac{270 \text{ m}^3\text{/day net output}}{370 \text{ m}^3\text{/day gross output}} \times 0.40 = 0.29$$

(5) Total Capital Cost. 545 x 10^3 Dkr = $ 96.8 x 10^3 for a net output of 2 300 GJ/a gives $ 42/GJ/a.

(6) Operating and Maintenance Costs. These are for 1/8 man/a (~ 20 kDkr/a) and materials (~ 4 kDkr/a) giving 24 kDkr/a = $ 4.26 x 10^3/a for a nett output of 2 300 GJ/a resulting in an annual fixed O&M cost of $ 1.85/GJ/a.

4.13 Crude Oil Refining

The well established technology of crude oil refining is described below with extracts from Ref. 4.1.

A petroleum refinery is a combination of processes and operations designed to convert crude oil into various products. Crude may be a mixture of more than a thousand different hydrocarbons, together with trace quantities of such compounds as sulphur and nitrogen. The crude is first separated by distillation into fractions selected on the basis of boiling points; the relative volume of each fraction is determined by the type of crude used.

Since the relative volume of each fraction produced by merely separating the crude may not conform to the relative market demand for each fraction, some of the separation products are converted into products having a greater demand by splitting, uniting, or rearranging the original molecules.

The processes used in a refinery to accomplish the above conversions include distillation, sulphur removal, cracking, and reforming. Each refinery design is a unique combination of types and capacities of these processes.

As capital intensive cracking and reforming capacity is added to the basic distillation processes of the simplest "low conversion" or "hydro skimmer" type of refinery, it graduates into the class of "medium conversion" and eventually "high conversion" refineries.

Figure 4.7 gives a schematic of the process configuration for a typical medium to high conversion refinery.

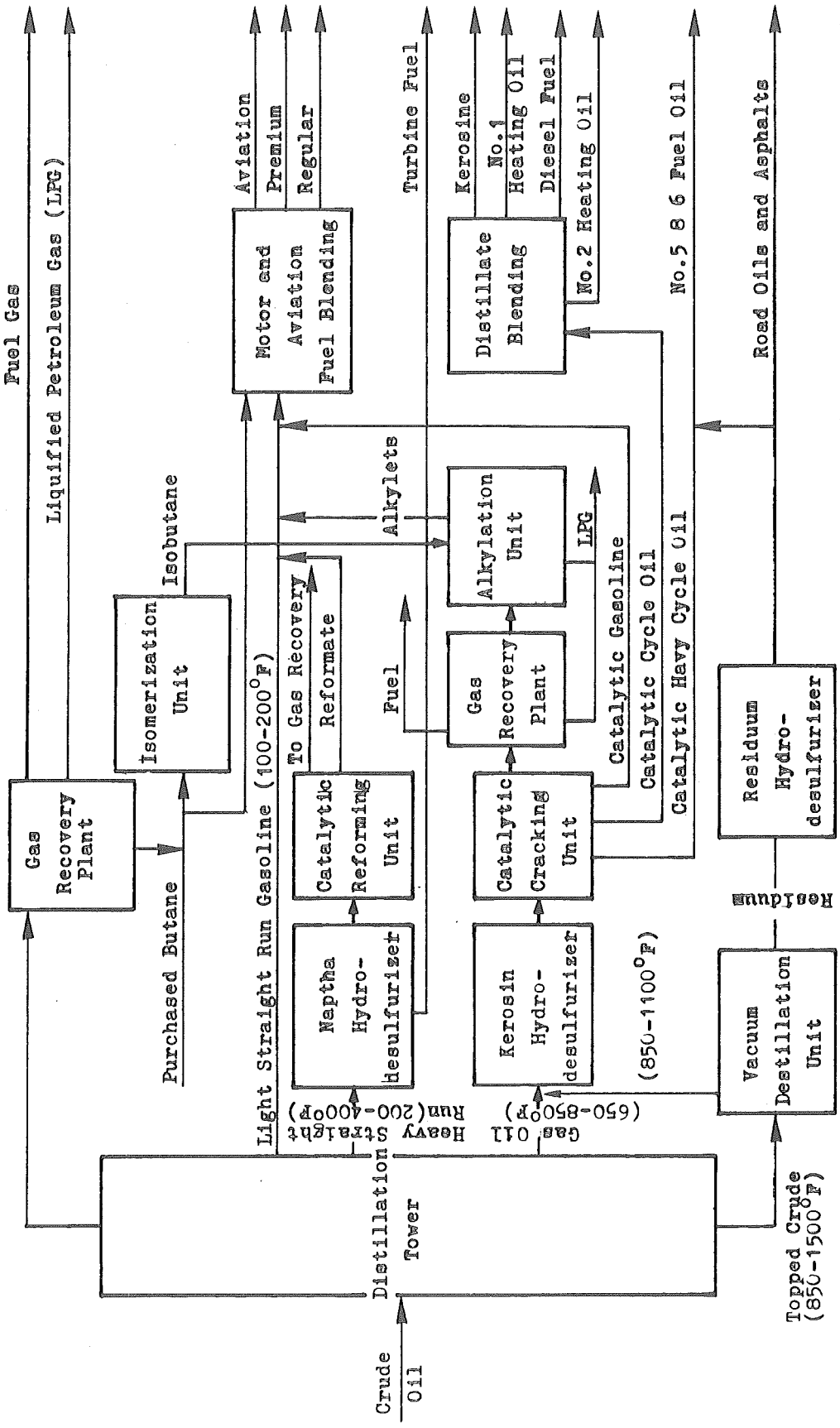


Figure 4.7: Typical Medium/High Conversion Refinery

The feedstock for a refinery is crude oil, but there is a limited range of crudes that a particular refinery can process efficiently. The important feedstock characteristics are density (API gravity), sulphur content, and the quantities of other impurities such as nitrogen and salts. If an appropriate feedstock is not available from a single source, different crudes are blended to obtain the desired characteristics. In addition to crude oil, feedstock can include natural gas liquids or synthetic crude (syncrude) from oil shale or coal liquefaction. Syncrude usually requires pre-treatment (which can add significant costs) before submission to a conventional refinery.

The principal products of refineries are gasoline, jet fuels, kerosene, diesel and fuel oils. Lubricants, waxes and solvents, petrochemical feedstocks, LPG and asphalt are also produced. The proportions of the principal products vary with the feedstock, refinery design, and time of year. For example, refineries may emphasise gasoline production in summer and heating oil production in winter.

In section 4.13.1 a summary is given of characterizations received describing complete oil refineries and in section 4.13.2 characterizations of individual refinery units are discussed.

4.13.1 Complete Oil Refineries - Characterization Summary

Two characterizations were received from Japan describing complete oil refineries. One corresponds to the "average" plant producing a yield of oil products in the fractions characteristic for the country as a whole in 1980. The other is for an upgrading refinery converting atmospheric distillate residuals, liquefied coal, oil-sand bitumen or shale oil product to high grade oil products. These characterizations are summarized in Table 4.12.

TABLE 4.14 - Complete Oil Refineries - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	y
Japan "Standard" 1980 Plant	290	exist-ing	261	90	95	92	2.40	0.179	0.145	20
Japan Upgrading Refinery	92.5	1980	79	85	90	88	2.39	0.224	0.197	20

Assessors

Japan:- Koyama, S., Kashihara, T., and Endo, E.,
Electrotechnical Laboratory, Sakura-Mura, Ibaraki

Notes:

(1) All energy quantities are based on NCV of fuels. Design capacities and all specific costs are expressed in terms of energy outputs of plants.

(2) Standard 1980 Refinery - Japan

The refinery described in this characterization is an average of the refineries existing in Japan in 1980. As there exist many types of refineries depending on various crude oils and combinations of system components, which are very difficult to include in an energy system model in detail, an average representative system was characterized. Yields of oil products were calculated from oil refinery statistics. These are expressed as decimal fractions of oil input energy (NCV basis) below.

		Median Value	Upper Value
Input	Crude Oil	1.000	1.000
	LPG	0.022	0.026
	Gasoline	0.137	0.156
	Naphtha	0.082	0.092
Output	Jet Fuel	0.019	0.038
	Kerosene	0.095	0.114
	Light Distillate Oil	0.186	0.215
	Heavy Distillate Oil	0.379	0.421
	TOTAL	0.920	

For individual product outputs to reach the upper values given above, outputs of other products are correspondingly reduced to be consistent with a total output fraction of 0.92.
Input (1.000) - Output (0.920) = refinery use of fuel

+ losses = 0.08

Fixed O&M costs are broken down as follows:

	$/GJ/a
Tax (fixed asset tax and miscellaneous)	0.049
Repair, labour, insurance and other	0.130
	0.179

Variable O&M costs are broken down as follows:

	$/GJ
Non-Energy Material Consumption	0.0052
Waste Disposal	0.0011
Part of Miscellaneous Tax	0.1391
	0.1454

(3) Upgrading Oil Refinery - Japan

The system is used for upgrading heavy quality oil or liquid fuel to higher grade oil products. Main processes are based on thermal cracking and gasification. Input fuels are atmospheric distillate residuals, liquified coal product, oil-sand bitumen and shale oil.

Yields of oil products are expressed as decimal fractions of liquid fuel input energy (NCV basis) on the next page.

		Median Value	Upper Value
Input	Heavy Quality Liquid Fuel	1.000	1.000
Output	Gas	0.109	0.139
	LPG	0.028	0.035
	Gasoline Naphtha	0.060	0.120
	Jet Fuel Kerosene	0.089	0.134
	Light Distillate Oil	0.120	0.147
	Heavy Distillate Oil	0.455	0.545
	Coke	0.020	0.030
	TOTAL	0.881	

For individual product outputs to reach the upper values given above, outputs of other products are correspondingly reduced to be consistent with a total output fraction of 0.881.
Input (1.000) - output (0.881) = 0.119 = refinery use of fuel + losses

Fixed O&M Costs are broken down as follows:

	$/GJ/a
Tax (fixed asset tax and miscellaneous)	0.049
Repair, labour, insurance and other	0.174
	0.224

Variable O&M costs are broken down as follows:

	$/GJ
Non-Energy material consumption	0.040
Waste disposal	0.011
Part of miscellaneous tax	0.146
	0.197

4.13.2 Oil Refinery Subprocesses - Vacuum Distillation and Catalytic Cracking

The well established oil refinery processes of vacuum distillation and catalytic cracking are described below with extracts derived from Ref. 4.1 and the Australian characterizations.

Distillation is a process of progressively heating crude oil in a column and drawing off various components at their different boiling points. The very light hydrocarbons, such as gasoline, boil at less than 120 °C, while the boiling points of the heavy or residual fuel oils are more than 480 °C. Distillation in a refinery first occurs in an atmospheric pressure distillation tower. The lower boiling point (lighter) fractions move up the tower before condensing out. The heavy residual fractions

(variously described as topped crude, long residues or atmospheric distillation bottoms) leaving the atmospheric column are processed in a vacuum distillation column to separate very high boiling point components. The lower end of the boiling range of the residual feedstock to the vacuum column is dependent on both crude type and refinery design, but a reasonable value is 345 °C.

Two main output streams come from the vacuum distillation unit; one is a stream suitable for input to a catalytic cracker (vacuum gas oil or cracker feedstock); the other is a heavy residue (vacuum bottoms, short residue) which is used mostly for non-energy processes, including manufacture of asphalts and lubricating oils.

The relative proportions of the two streams depends on the properties of the crude oil from which the topped crude is derived. The proportions of vacuum gas oil may be as low as 40 % (by weight) for a heavy crude (e.g. Arab Heavy), while for a very light crude (e.g. Attaka), virtually 100 % of the topped crude may be regarded as gas oil.

Cracking is a process of breaking up large molecules in the cracker feedstock to form smaller molecules with higher energy content. Two kinds of cracking processes, catalytic cracking and hydrocracking, are presently used in modern refineries, having replaced thermal cracking processes used earlier.

Catalytic cracking (cat cracking) accounts for the vast majority of cracking processes in use today. Cracking catalysts are zeolites, synthetic formulations of alumina in silica. Modern cat crackers use fluidized beds of catalyst. Cat cracking catalysts rapidly become fouled with carbon and must be frequently regenerated; thus, regenerators are included as an integral part of the cat cracking reactor. The regenerator burns the carbon with air to form carbon monoxide, which is then used for refinery process heat. As with other refinery processes, the cracked hydrocarbons are separated in a distillation column.

Hydrocracking carries out the cracking reactions under high pressures (2000 to 2500 psi) and temperatures (about 430 °C) in the presence of hydrogen and a catalyst in fixed-bed reactors. Because of the high pressures and temperatures, and the hydrogen requirement, hydrocracking equipment is relatively expensive. However, hydrocracking should become more competitive in the future because it generates higher octane products and does not leave a carbon residue.

4.13.3 Oil Refinery Subprocesses - Characterization Summary

Australia provided characterizations of two refinery subprocesses; vacuum distillation and catalytic cracking. These are summarized in Table 4.15.

TABLE 4.15 - Oil Refinery Subprocesses - Characterization Summary

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	PJ/a		PJ	%	%	%	$/GJ/a	$/GJ/a	$/GJ	Yrs
Australia (Vacuum Distillation)	73	exist-ing	66	90	90	98	0.199	→	0.0337	30
Australia (Catalytic Cracker)	51	exist-ing	46	90	90	81	0.972	→	0.121	30

Assessor

Australia:- Bath, P.T., AAEC Research Establishment,
Private Mailbag, Sutherland, N.S.W., 2232

Notes:

(1) Assessor used GCV of fuels in calculating energy values. (For this report energy quantities were converted to a NCV basis using a NCV/GCV ratio of 0.95 for all refinery input and output fuels).

(2) Vacuum Distillation

Design capacity corresponds to a unit of 32600 BPSD representing the average size of units in the 6 largest refineries in Australia in 1978 (Ref. 4.20). Feasible plant size range is quoted as 10 000 - 120 000 BPSD in Reference 4.21. Reference 4.22 states that the largest current plant design is 130 000 BPSD.

Energy inputs per year at full load are

	PJ
Topped crude	73.15
Refinery fuel	2.18
Electricity	0.01
	75.34

Energy content of topped crude has been taken as 41.63 GJ/te (NCV), equal to 95 % of the GCV figure quoted for fuel oil in Reference 4.23. Density is 0.929 kg/l.

Energy outputs per year at full load are in the ranges

	PJ
Vacuum gas oil	43.7 - 65.5
Vacuum bottoms	29.4 - 7.6
	73.1

Energy content and density of both output streams are assumed to be the same as topped crude.

Maximum annual availability of 90 % is the standard industry value (Ref. 4.24).

The capacity factor is taken to be equal to maximum availability but may vary downwards. In Australia, the historical value is about 80 %, probably now 85 % (Ref. 4.24).

All costs were originally in $ A (1978). Multiplication by 1.372 gave $ U.S. (1980). Refining plant costs in Australia in 1978 were 40 % higher than U.S. costs. Note that refining plant costs are subject to increasing returns to scale.

Capital and operating costs are based on Ref. 4.25. Economic lifetime is from Ref. 4.21.

(3) Catalytic Cracking

Design capacity corresponds to a unit of 28 700 BPSD representing the average size of units in the 6 largest refineries in Australia (Ref. 4.20). Feasible plant size range is quoted at 2 000 - 100 000 BPSD in Ref. 4.21. Reference 4.22 states that plant up to 200 000 BPSD are currently planned.

Energy inputs per year at full load are

	PJ
Cracker feedstock	64
Electricity	0.23

Cracker feedstock usually includes straight run and vacuum gas oils with boiling temperatures above 210 °C. The energy content (NCV) of the feedstock has been taken as 43.31 GJ/te; i.e. 95 % of the GCV value in Ref. 4.34 for industrial diesel oil. Density taken as 0.847 kg/l.

Refinery fuel input of 5.5 % of the energy content of the input stream is required. It is assumed that this is met from combustion of refinery gases produced as byproducts of the cracking process, so that no net fuel input occurs.

Electricity input calculated from 6 kWh/bbl feed (Ref. 4.21).
It is assumed that all light gas output is used as process fuel.

Energy outputs per year at full load are in the ranges

	PJ
Gasoline	26.6 - 39.9
Light distillate	16.6 - 6.6
Heavy distillate	7.6 - 4.3
	50.8

Gasoline here covers C_5+ and also includes butanes used as alkylation feedstocks. Light distillate may be regarded as approximately equivalent to aue diesel oil and heavy distillate as fuel oil.

The following NCV values are assumed (95 % of GCV values in Ref. 4.23)

	GJ/te
Gasoline	44.78
Light distillate	43.50
Heavy distillate	43.31

Energy outputs have been calculated by estimating weight fractions of output streams and converting to energy terms using the NCVs above. The proportions of end-products are determined by the operating

conditions and by the nature of the crude from which the feedstock is derived. The following breakdown covers the range

	Low Conversion (weight %)	High Conversion (weight %)
Gasoline	42	63
Light distillate	27	11
Heavy distillate	13	7

Comments above on maximum annual availability, capacity factor, costs and lifetime of vacuum distillation apply equally to the catalytic cracker characterization.

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5. RENEWABLE CONVERSION

5.1 Renewable Energy Sources

Classifying the four basic energy sources available on earth can be made either according to the energy carriers or according to the physical origin of the energy sources. A classification based on the physical origin is summarized below:-

1. Radiation Energy of the Sun

   Direct Use

   - solar energy

   Indirect Use (energy carriers: water, air, fossil fuel)

   - chemical binding energy in fossil fuels
   - kinetic wave energy of the oceans
   - kinetic current energy of the oceans
   - ocean thermal gradient
   - chemical binding energy in fossil fuels
   - potential energy of the water

2. Nuclear Binding Energy

   - nuclear fission
   - nuclear fusion.

3. Geothermal Energy

   - convective heat transport (energy carriers: water)
   - heat conduction (energy carriers: rock).

4. Tidal Energy

An estimate of the theoretical potential of those energy sources which are not used commercially gives the following results:

Radiation energy of the sun:	appr. 3.6×10^{24} J/a
Nuclear fusion:	appr. 7×10^{30} J (deuterium and lithium)
Geothermal energy:	
- energy carrier water:	16×10^{21} J
- energy carrier rock:	12.5×10^{25} J
Tidal energy:	9×10^{19} J/a

Energy sources are called "renewable" if they are inexhaustible within human measures of time. This implies that except for the fossil and nuclear fuels and strictly speaking also the geothermal heat sources, all other energy sources quoted in the summary above are renewable sources. In this chapter the technological concepts using "renewable energy carriers" will be discussed and, where practical experience has been gained, technical and economical assessments are presented. The different "geothermal technologies" will be treated likewise, as they are considered as one of the important alternative options to replace fossil fuels in the energy production.

5.2 Wind Energy Conversion Systems

5.2.1 Introduction

Approximately 2 % the insolation on earth is converted to kinetic energy in the atmosphere. Port of this kinetic energy (approximately 3 % or 3.6×10^{21} J/a) theoretically could be used in wind energy conversion systems, assuming a 10 % increase in friction with the earth's surface caused by the wind machines.

Wind conversion systems have been used for several centuries. To perform mechanical work in pumping water or milling grain. The main feature of all these systems was that the mechanical energy was consumed directly at the place where it was generated.

Increasing costs of primary fuels, especially in the last decade, led to intensified research into wind energy conversion systems for electricity generation in large central units as well as in small decentralised devices. The requirement to generate the electric power with a constant frequency at a nearly constant voltage level, posed a number of technological problems. As the wind speed (which is the decisive parameter) varies, the theoretical output varies as the wind speed cubed. If mechanical energy is produced this does not cause difficulties. In alternating current (AC) electric systems, however, the grid frequency has to be the same for alle generating plant coupled to the grid. At the same time, the demand for electricity has to be met at every moment of operation. To a certain degree an extended electric grid has the capability to absorb varying inputs (self-adjusting effect) provided the varying production represents only a small fraction of the total production. If this is not the case, measures have to be taken to stabilize output and frequency which a wind energy conversion system feeds into the grid or supplies to a consumer.

The driving shaft of the electricity generator is generally linked to the windmill rotor through a gear box, which allows an adjustment for different wind speed ranges. Within these ranges momentary wind speed variations (gusts) are equalized by pitch control of the rotor blades. This results in a stable output which varies over a limited range. Further improvement is possible if, instead of a synchronous generator, an asynchronous generator is used. The slip-ring rotor of such an asynchronous generator can then externally be fed with a voltage at a controlled frequency which compensates for the difference between generator rotation frequency and required constant stator frequency. This fairly sophisticated method will be tested in the German GROWIAN system.

Despite the technical methods described above, the essential difficulty of wind electricity generation remains unsolved. The electricity generation in a wind energy conversion system is essentially determined by the availability of the wind. Production is impossible at too low or too high wind velocities. If production is possible, the potential output of a wind machine is always a function of the available wind velocity. Therefore wind energy conversion systems for electricity production necessarily have to be backed up with storage or with conventional fossil systems as a stand-by reserve, in order to meet the peak load on the grid. Large compound grids normally have a certain reserve capability which allows the installation of a limited number of wind machines without back-up systems. Further implementation of wind energy conversion systems for electricity production, however, will depend on further developments in the storage technologies.

In the main, two fundamentally different designs of wind machines can be distinguished, the horizontal-axis and the vertical-axis concept. In larger wind energy conversion systems horizontal-axis wind turbines have prevailed. They are generally more efficient than vertical-axis turbines, where the rotor speed cannot exceed the wind speed. The advantages of vertical-axis turbines on the other hand consist in the fact that they are easier and less expensive to build. One major reason for this is that vertical-axis machines operate equally well regardless of the direction of the wind and a control system is not required. This is required in horizontal-axis machines so as to sense changes in wind direction and adjust the wind turbine platform accordingly.

5.2.2 Central Wind Energy Conversion Systems - Characterization Summary

In the last decade, research and development on central electricity generating wind machines has been intensified in most

of the countries participating in the IEA Energy Technology Systems Analyis Project. The major objective of these projects was the demonstration of the technical feasibility of wind electricity generation not only in large central units but also in small, autonomous units. The problems which had to be solved in these feasibility studies have already been discussed in section 5.2.1. The following list gives a summary and a short description of a number of projects demonstrating the wind electricity generation in large central units (country name in brackets):

(1) Nibe-A, Central Wind Turbine (Denmark)
The Nibe-A wind turbine drives a 630 kW induction generator which is coupled to the utility grid.
Turbine characteristics:

- horizontal-axis machine
- 3-bladed upwind rotor, staged construction
- cut-in wind speed: 6.5 m/s
- cut-out wind speed: 25 m/s
- full power regime: 14-25 m/s (550-630 kW)
- hub height: 45 m
- electric induction generator: 630 kW 3 x 6 kV

(2) GROWIAN I, 3 MW Wind Turbine (Germany)
The system feeds directly into the grid, no storage.
Turbine characteristics:

- horizontal-axis machine
- 2-bladed rotor with self-adjusting hub
- stay mast
- rotor diameter: 100.4 m
- rotor area: 78.54 m^2
- nominal rotor speed: 18.5 rpm + 15 %
- hub height: 100 m
- cut-in wind speed 6.3 m/s
- cut-out wind speed 24 m/s
- full power regime: 11.8 - 24 m/s
- asyncronous AC generator, externally fed slip-ring rotor for frequency control

(3) Central 100 kW Wind Turbine (Japan)
The system feeds directly into the grid.
Turbine characteristics:

- horizontal-axis machine
- 2-bladed upwind rotor
- rotor diameter: 25 m
- rotor axis angle: 7 °
- rated rotor speed: 70 rpm
- hub height: 30 m
- cut-in wind speed: 5 m/s
- rated wind speed: 10 m/s
- cut-out wind speed: 17 m/s
- syncronous AC generator

(4) 3 MW Wind Turbine (Norway)
(Assessment based on the Swedish WTS-3 system)
Turbine characteristics:

- horizontal-axis machine
- rotor diameter: 78 m
- hub height: 80 m
- rotor speed: 25 rpm
- synchronous AC generator 3 MW
- cut-in wind speed: 5 m/s
- cut-out wind speed: 21 m/s
- rated wind speed: 14.2 m/s

(5) 2.5 MW Wind Turbine (Sweden)
The system is directly coupled to the grid. No storage system.
Turbine characteristics:

- horizontal-axis machine
- 2-bladed rotor
- assumed average wind speed at hub height: 7 - 7.5 m/s

Further details are not specified.

(6) Central 3 MW Wind Turbine (United Kingdom)
Onshore wind electricity generation.
Turbine characteristics:

- horizontal-axis machine
- 2-bladed rotor
- rotor diameter 60 m

Further details are not specified.

(7) Central 100 MW Wind Turbine (Spain)
(Tarifa-1-System)
The system is directly feeding into the grid. No storage.
Turbine characteristics:

- horizontal-axis machine
- 3-bladed downwind rotor
- rotor diameter: 20 m
- rotor speed: 48 rpm
- cut-in wind speed: 6 m/s
- cut-out wind speed: 22 m/s
- full power regime: 12 - 22 m/s
- 100 kW synchronous AC generator

Table 5.1 summarizes the technical and economic key data of the wind energy conversion systems described above. It should, however, clearly be noted that the given set of data is inconsistent in the sense that some characterizations (Tarifa-1-System, Japanese 100 kW-machine) present technical and economic figures derived from the experience with demonstration plants while other characterizations (GROWIAN, WTS-3, Nibe-A) assess the future technical and, first of all, economic potential of wind energy conversion systems. A detailed explanation is given in the notes to table 5.1.

TABLE 5.1 - Technical and Economic Key Data of Large Wind Energy Conversion Systems

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	kW_e	-	TJ	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
Nibe-A Denmark	630	c.a.	4.4	22	47	19.5	1350	20	←	25
GROWIAN I Germany	3000	1982	23.6	25	60	32	1802	28	←	25
100 kW-WECS Japan	100	1985	0.883	28	40	25	2979	135	←	25
WTS-3 Norway	3000	1990	31.2	33	70	24	1065	20	←	25
2.5 MW Turbine Sweden	2500	1985	22	28	55-60	30	1340	36	←	30
3 MW Turbine United Kingdom	3000	1986	23.8	25	55	25	1910		0.77	25
Tarifa-1-System Spain	100	1985				35	5053			

Assessors

Denmark:- Christensen, C.J., Risø, Roskilde

Germany:- Müller, M., KFA/STE, Postbox 1913, D-5170 Jülich

Japan:- Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki

Norway:- Nitteberg, J., Institutt for Energiteknikk,
N-2007 Kjeller

Sweden:- Leman, G., Energy R&D Commission, Stockholm

United Kingdom:- Ward, A.V., ETSU, Harwell

Spain:- Centro de Estudios de la Energia, Agustin de Foxa,
29-Madrid-16

Notes:

(1) Design Capacity

The design capacity given in the summary table is the nominal capacity of the generators installed in the wind energy conversion systems.

(2) Capacity Factor

In the characterizations it has been assumed that the wind energy conversion systems are operating as base load plants. This means that all the output from the wind electricity generation is absorbed by the grid.

The wide range, over which the capacity factors in the summary table vary, indicates that the production of a wind power plant essentially depends on the sitespecific wind conditions. In most of the characterizations an attempt has been made to estimate the capacity factor, averaging over all site locations suited for the installation of a wind machine of the given size. The uncertainty in these estimates, taking into account the site-dependent variations of the wind conditions, however, is so large that capacity factors of 33 or even more per cent seem possible at ideal wind conditions.

(3) TABLE 5.2 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being Less Than	10 % Probability of Being Greater Than	Unit
Denmark (Nibe-A)	Maximum Annual Energy Output	4.4			TJe
	year-to-year variability (average site)		3.6	5.2	TJe
	- site variability (average year)		1.6	5.1	TJe
	Maximum Annual Availability	47	42	52	%
	Overall Efficiency	19.5	18	30	%
	Total Capital Cost	1350	1000	2000	$/kW$_e$
	Fixed O&M Cost	20	20	90	$/kW$_e$
	Economic Lifetime	25	5	30	yrs
Germany (GROWIAN I)	Capacity Factor	25	20	46	%
	Maximum Annual Availability	60	45	70	%
	Overall Efficiency	32	30	34	%
	Total Capital Cost	1802	1107	2120	$/kW$_e$
	Fixed O&M Cost	28	22	33	$/kW$_e$
	Economic Lifetime	25	20	30	yrs
Norway (WTS-3)	Capacity Factor	33	23	53	%
	Maximum Annual Availability	70	55	75	%
	Overall Efficiency	24	15	30	%
	Total Capital Cost	1065	950	1450	$/kW$_e$
	Fixed O&M Cost	20	13	42	$/kW$_e$
	Economic Lifetime	25	15	30	yrs
Sweden	Capacity Factor	28	25	32	%
	Total Capital Cost	1340	980	1800	$/kW$_e$
	Fixed O&M Cost	36	26	54	$/kW$_e$
United Kingdom	Capacity Factor	25	20	40	%
	Total Capital Cost	1910	1225	2660	$/kW$_e$
	Variable O&M Cost	0.77	0.19	1.27	$/GJ
	Economic Lifetime	25	20	30	yrs

(4) Total Capital Cost

In two characterizations, 100 kW-Windmill (Japan), Tarifa-1 (Spain)) the total capital costs for the installation of the demonstration plant are given, while in the other characterizations an estimate of the potential target cost is tried, assuming a series production of the wind machines (in the Norwegian and German characterization: appr. 100 windmills).

(5) Operating and Maintenance Cost

The variable O&M costs of 0.67 $\$/GJ_e$ in the American characterization correspond to 12 $\$/kW_e$ fixed O&M costs, if one assumes the system to operate with a capacity factor of 53 %.

The large operating and maintenance costs in the Japanese characterization (135 $/kW) result from the expenses for the administrative infrastructure of the utility (overheads), operating the wind machine, and from the labour costs which have been fully charged to the O&M cost of the fairly small (100 kW) system.

5.2.3 Local Wind Energy Conversion Systems - Characterization Summary

Many experts consider small local wind turbines for electricity generation as the more promising way for utilizing the wind energy, as a number of difficulties with electricity generation in large units can be solved more easily in small systems. First of all the quality requirements of the generated electricity (voltage, frequency, power) are not so stringent as in a central generation plant, especially not if the utility grid is used as a buffer. Secondly, the back-up problem does not occur so drastically in small generation units, as the utility grid

can serve as a backing system. Additionally, there are a number of simple and cheap storage possibilities (especially heat storages), if the wind machine is not exclusively operated as a generator substituting electricity from the grid, but also as primary fuel "saver", e.g. in the residential heating system.

In the following such a small wind turbine is described, which is coupled to the utility grid (country name in brackets):

55-kW Wind Energy Conversion System (Denmark)
The wind machine is coupled to the utility grid. Additionally, it feeds a resistance heater in a central heating system, in order to allow the user to utilize the largest possible fraction of the electricity produced by the wind turbine.

Turbine characteristics:

- horizontal-axis machine
- 3-bladed upwind rotor
- stall-regulated
- rotor diameter: 15 m
- hub height: 19 m
- cut-in wind speed: 4.5 m/s
- full power regime: from 11.8 m/s upwards
- 55 kW electric induction generation, 3 x 380 V
- directly (no transformer) coupled to the grid.

TABLE 5.3 - Technical and Economic Key Data of Small, Grid Connected Wind Energy Conversion Systems

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	kW_e	-	GJ	%	%	%	$/$kW_e$	$/$kW_e$	$/$GJ_e$	Yrs
Denmark	55	c.a.	363	21	54	28	910	13	←	20

Assessors

Denmark:- Christensen, C.J. Risø, Roskilde

Notes:

(1) TABLE 5.4 - Uncertainty Ranges

Item	Median Value	10 % Probability of Being		Unit
		Less Than	Greater Than	
Maximum Annual Energy Output	363			GJ_e
-year-to-year variability (average site)		290	436	GJ_e
-site variability (average year)		176	423	GJ_e
Maximum Annual Availability	54	48	60	%
Overall Efficiency	28	18	31	%
Total Capital Cost	910	750	1070	$/$kW_e$
Fixed O&M Cost	13	10	36	$/$kW_e$

As indicated above, small wind electricity generators feeding a resistance heater in the central heating system can serve as primary fuel "saver" in the residential useful energy production. If the windmill is exclusively operated in such a way, a coupling to the utility grid is superfluous. This essentially facilitates the design of the wind turbine, as a frequency stable output (grid frequency) is not required any longer.

The rotor thus is allowed to run at a variable speed. The power can then simply be regulated by turning the rotor out of the wind. In Table 5.3 the key data of such a windmill, characterized by the Danish project participant are listed. The main turbine characteristics of the wind turbine are:

- horizontal-axis, multi-vane mill
- 16 vanes
- rotor diameter 6.3 m
- hub height: 13.5 m
- runs at all speeds
- wind speed, at which the power generation starts: 3 m/s
- full power regime: from 14.5 m/s wind speed upwards
- 3-phase electric synchronous generator, 10 kW.

TABLE 5.5 - Technical and Economic Key Data of the Danish Multi-Vane Windmill

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	kW_e	-	GJ_e	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
Denmark	10	c.a.	34	8.3	85	16	1250	18	←	20

Notes:

(1) The multi-vane windmill is commercially available. The higher capital costs, compared to the grid-coupled 55 kW windmill characterized in table 5.2, result from the different scales of the systems.

(2) TABLE 5.6 - Uncertainty Ranges

Item	Median Value	10 % Probability of Being		Unit
		Less Than	Greater Than	
Annual Energy Output	34			GJ_e
-year-to-year variability (average site)		28	38	GJ_e
-site variability (average year)		16	50	GJ_e
Maximum Annual Availability	85	72	87	%
Capacity Factor	8.3	5	13	%
Overall Efficiency	16	10	25	%
Total Capital Cost	1250	980	1420	$\$/kW_e$
Fixed O&M Cost	18	10	25	$\$/kW_e$
Economic Lifetime	20	5	25	yrs

5.3 Wave Energy Conversion Systems

5.3.1 Introduction

Figure 5.1 shows one of the possible concepts to utilize wave energy for electricity production, the so-called oscillating water column system. The waves enter a chamber (1) through a gate (2) where their energy causes an up-and-down motion of the water-column. The upwards motion of the water-displaces the remaining air in the oscillating chamber. The air passes through a set of valves to drive an air (Wells) turbine (3). By

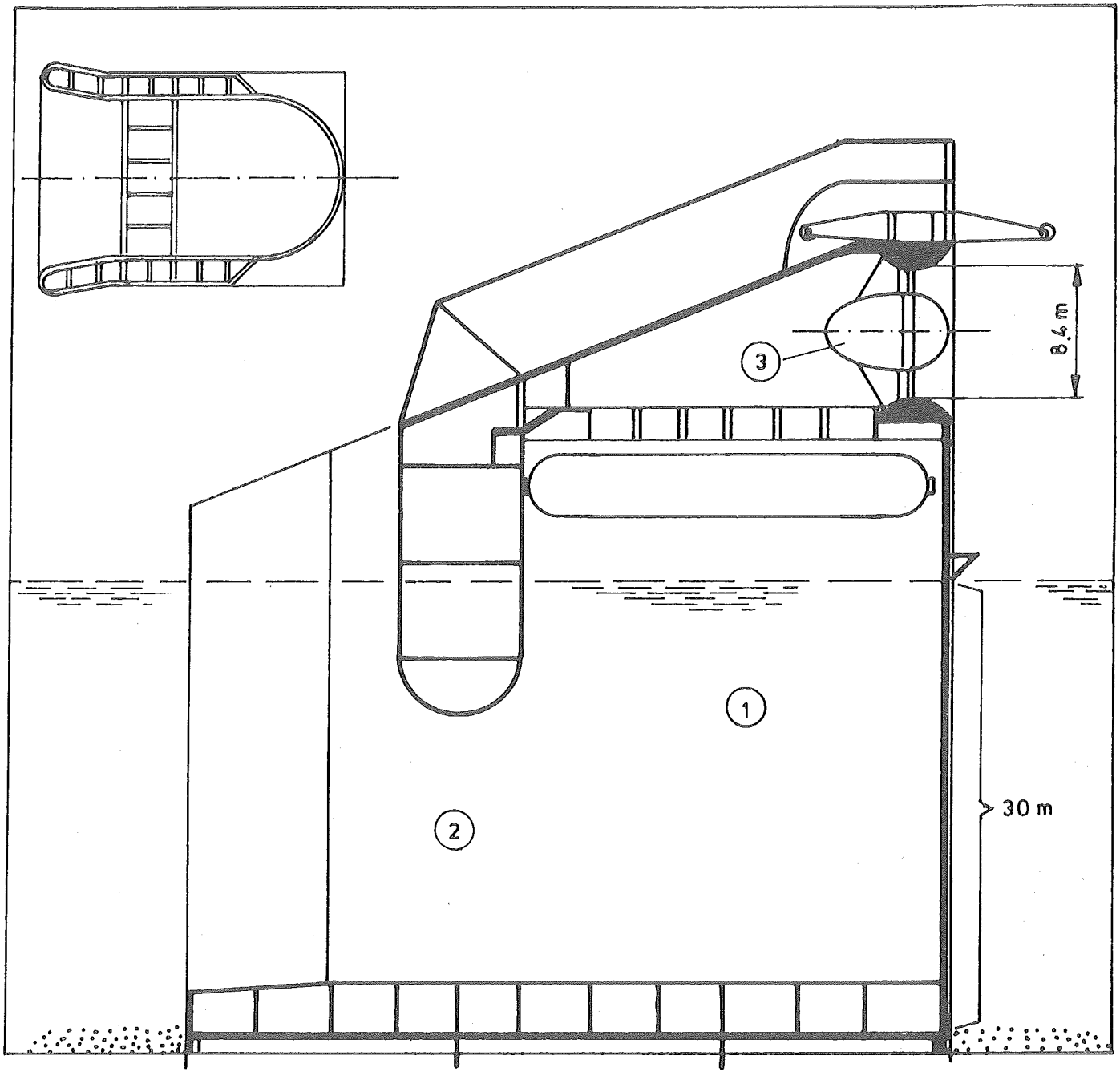


Figure 5.1: Oscillating Water Column
- Wave Energy Conversion System

the subsequent downwards motion of the water-column causes the air to flow back into the chamber and the process starts again. A wave power plant, based on the principle of the oscillating water column, is generally composed of several units (unit capacity: 8 MW) arranged in a row about 1-10 km off the coast.

A different concept of a wave energy conversion unit consists of a floating platform with an air turbine moored offshore towards the direction of the waves.

5.3.2 Characterization Summary

Three characterizations of wave energy conversion systems have been provided by project participants. Two systems assessed for this report are based on the oscillating water column principles. The third system utilizes a floating platform for the conversion of the wave energy. In the following a short description of the characterized systems is given (country name in brackets):

(1) 8 MW-Oscillating Water Column Power Plant (Norway)
The complete power station consists of 25 units (as described in the preceding section), with a capacity of 8 MW each. The units are arranged in a row 1-10 km off the coast (see figure 5.2).

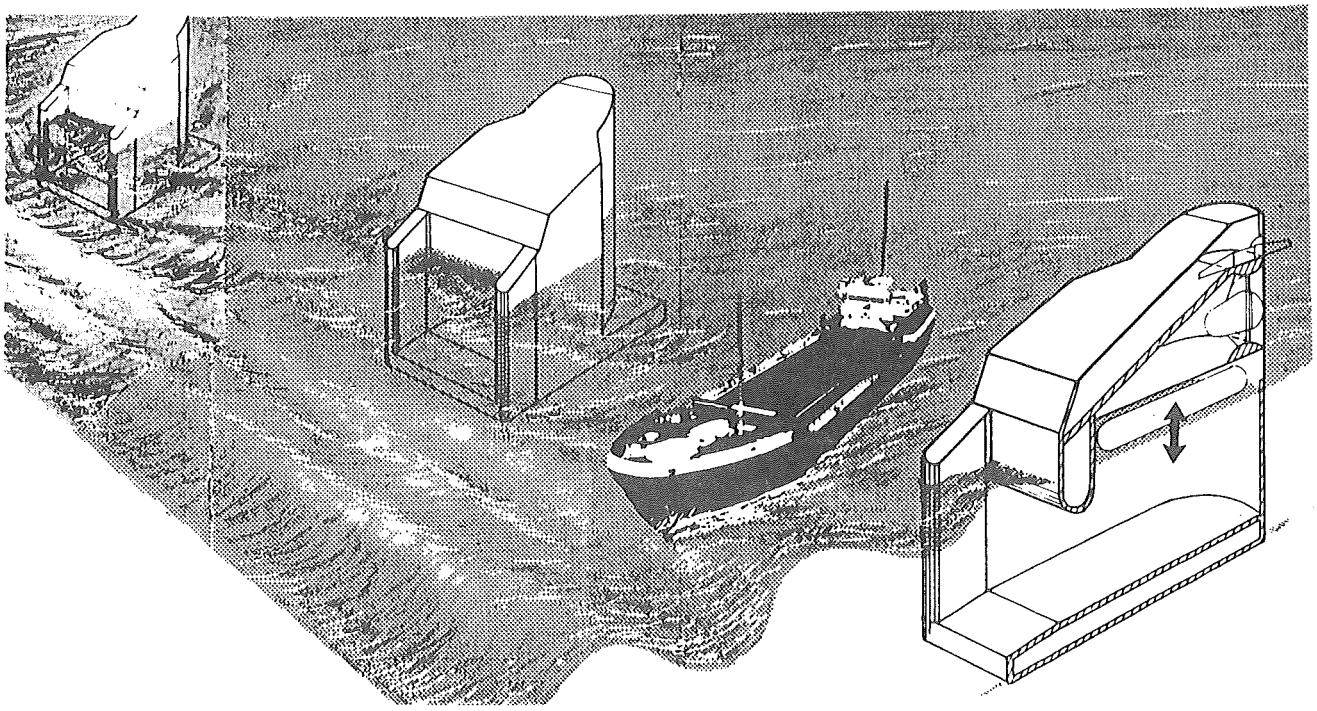


Figure 5.2: Norwegian Oscillating Water Column Power Plant

Technical details of the 8 MW-generation unit:

- width of the gate: 160 m
- height of the oscillation chamber: 30 m
- air turbine rotor diameter: 8.4 m
- turbine rotor speed: 428 r.p.m.

The energy content of the waves (in kW per m wave front) 10 km off the Norwegian coast has been estimated as follows:

	kW/m
Lista (Southern Norway)	24
Bremanger (Western Norway)	38
Lofoten (Northern Norway)	19

The calculations have been carried out for the western Norwegian coast.

(2) 2 GW-Oscillating Water Column Wave Power Plant (United Kingdom)
The 2 GW-wave power plant consists of ten 200 MW-subsystems each constructed of 25 8 MW-oscillating water column units, as characterized by the Norwegian project participant. The technical details of each unit are the same as in the Norwegian case.

(3) 1.5 MW-Wave Power Plant (Japan)
The wave electricity generation system consists of a floating platform, which is moored offshore towards the direction of the waves. Further descriptive information is not available at present.

TABLE 5.7 - Technical and Economic Key Data of Wave Energy Conversion Systems

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	TJ_e	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
Norway	8	1995	26	11	95	14	2030	25	←	25
United Kingdom	2000	1985	15770	25	73	25	5003	77		25
Japan	1.5	1990	8.04	17	67	17	2567	171.1	←	30

Assessors

Norway:- Ormhaug, T., Institute for Energy Technology, N-2007 Kjeller

United Kingdom:- Ward, A.V., ETSU, Harwell

Japan:- Ohno, K., Japan Marine Science and Technology Center, Yokosuka, Kanagawa

Notes:

(1) Total Capital Cost

The capital cost for the Norwegian wave power plant can be broken down as follows:

Construction:	1250 $/kW$_e$
Transportation:	25 $/kW$_e$
Engineering, geological survey:	300 $/kW$_e$
Owner's cost:	125 $/kW$_e$
Interest during construction:	330 $/kW$_e$
TOTAL:	2030 $/kW$_e$

For the capital cost of the U.K. system, which is technically the same as the Norwegian wave energy conversion system, the following breakdown has been given:

Structural cost:	2760 $/kW$_e$
M&E plant:	690 $/kW$_e$
Power take-off:	50 $/kW$_e$
Site preparation, towage and enhancement operations:	449 $/kW$_e$
TOTAL:	3949 $/kW$_e$

(2) Fixed Operating & Maintenance Cost

The fixed operating & maintenance costs of the Japanese wave energy conversion system cover the following expenses:

Interest:	65.7 $/kW$_e$
Labour, repairs:	52.7 $/kW$_e$
laneous costs (overheads)	52.7 $/kW$_e$
TOTAL:	171.1 $/kW$_e$

(3) TABLE 5.8 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being		Unit
			Less Than	Greater Than	
Norway	First Commercial Service Year	1995	1990	2000	-
	Maximum Annual Availability	26	15	45	TJe
	Capacity Factor	95	93	98	%
	Overall Efficiency	14	8	24	%
	Total Capital Cost	2030	1625	2650	$\$/kW_e$

In the other characterizations uncertainty ranges for the data entries were not specified.

5.4 Tidal Energy Conversion Systems

5.4.1 Introduction

The principle of a tidal energy conversion system is simple. A suitable bay with a sufficient tidal lift can be isolated from the sea by a barrage. On the incoming tide, the bay is filled through a number of open sluices in the barrage which are closed again when the highest water level is reached. As the tide recedes, a height difference develops between the barrage and the stored volume of water behind the barrage and the level of the sea. The stored water is then released through turbines thereby converting the potential energy of the stored water to mechanical, and finally to electric energy.

This "one-way" operation of the wave energy conversion system thus only allows electricity generation when the stored water is released to the sea (Fig. 5.3: A). A substantial increase of the energy production (appr. 20 %) can be achieved if the barrage is equipped with reversible turbines, which also operate when the bay is filling (Fig. 5.3: B).
Figure 5.3 shows the principle of the two possible modes of operation.

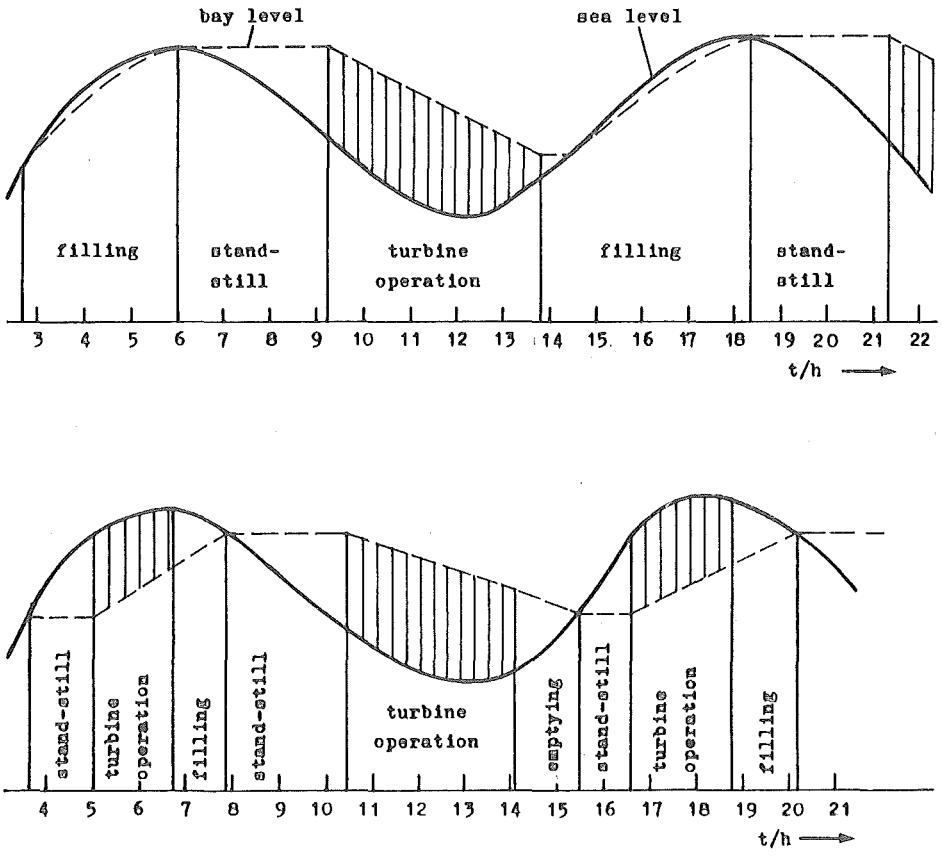


Figure 5.3: Modes of Operation of a Tidal Energy Conversion System

5.4.2 Characterization Summary

For this report a characterization of a tidal power plant in the Severn estuary (U.K., see fig. 5.4) has been provided by the British project participant.

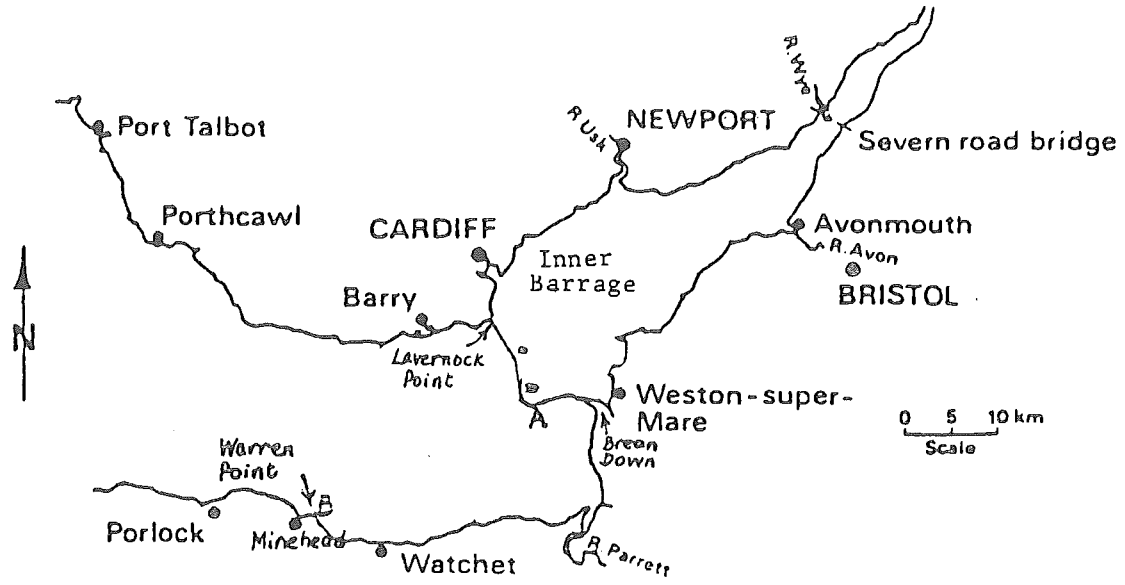


Figure 5.4: Map of the Severn Estuary District (U.K.)

The barrage between Lavernock Point and Brean Down isolates the Severn estuary from the sea. It is equipped with 160 45 MW turbogenerators (rotor diameter: 9 m) and 150 sluice equivalents (12 m² aperture). The system is designed as a one-way electricity generation system (see fig. 5.3: A).

TABLE 5.9 - Technical and Economic Key Data of Severn Barrage Tidal Power Plant

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW	-	PJ_e	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
United Kingdom	7200	2000	45.4	20	44	20	2378	11.2	-	60

Assessor

Ward, A.V., ETSU, Harwell, England

Notes:

(1) TABLE 5.10 - Uncertainty Ranges

Item	Median Value	10 % Probability of Being		Unit
		Less Than	Greater Than	
Total Capital Cost	2378	1538	1809	$/kW$_e$
Fixed O&M Cost	112	10	12	$/kW$_e$

5.5 Hydro Energy Conversion Systems

5.5.1 Introduction

Basic components of conventional hydroelectric resource systems are an initial water source, a storage reservoir, a pipe transport system, and a turbine-generator complex, in which the potential energy of the stored water is converted to electric energy. An essential pre-requisite for hydroelectric generation is an adequate quantity or flow rate of water together with a suitable elevation difference (also called "head") between the surface of the water storage and the outlet of the turbine discharge, which provides the necessary water pressure to drive the turbines. In some cases sufficient pressure may exist in a naturally flowing stream, but most often a "head" is obtained by building a barrage from which the water is then released via a pipe system.

Dams are normally built to achieve other objectives than maintaining an adequate elevation difference for hydroelectric generation, such as, providing significant water storage, flood control, recreational and water supply. Generally dams are classified as low or high, run-of-river or storage, and are of earth or concrete construction.

Low dams range up to about 30 m in elevation and are normally located on rivers of relatively continuous flow, where they most frequently function as run-of-river facilities with the water running continuously through the turbines. Run-of-river systems in general provide electricity for base loads rather than for peak demands.

High dams range from about 30 to 300 m in height. The water reservoirs isolated by these barrages are capable of storing large quantities of water. They are frequently located in mountainous regions where rivers have seasonal flows being dependent on snow run-off. The stored water there can be controlled to provide power during periods of peak electricity demand.

An important technique based on the water storage concept, however, is the pumped storage. In a pumped storage system electricity from other power sources (e.g. a nuclear power plant) is used to pump water from a low basin into an upper storage for subsequent hydroelectric generation during peak demand periods. The reason for using such a system is that electrical energy cannot be stored directly in large quantities and so this indirect storage system is used. In a central electricity generation electricity must be generated when it is required. Since the demand for electricity varies over a wide range, this results in a discontinuous and expensive operation of the electricity system's power plants. Pumped storage systems allow the stored energy to be released to the grid as peak electricity by hydroelectric generation. The result is a more continuous and cheaper load management in the grid.

5.5.2 Characterization Summary

For the report five characterizations of hydro power plants have been provided. In the following a short description of the characterized systems is given (country name in brackets):

(1) Run-Of-River Power Plant (Switzerland)
The system described in the characterization is located in the upper course of the river Rhine between Domat/Ems and Fläsch (Switzerland). Figure 5.5 shows the principle of a run-of-river electricity generation.

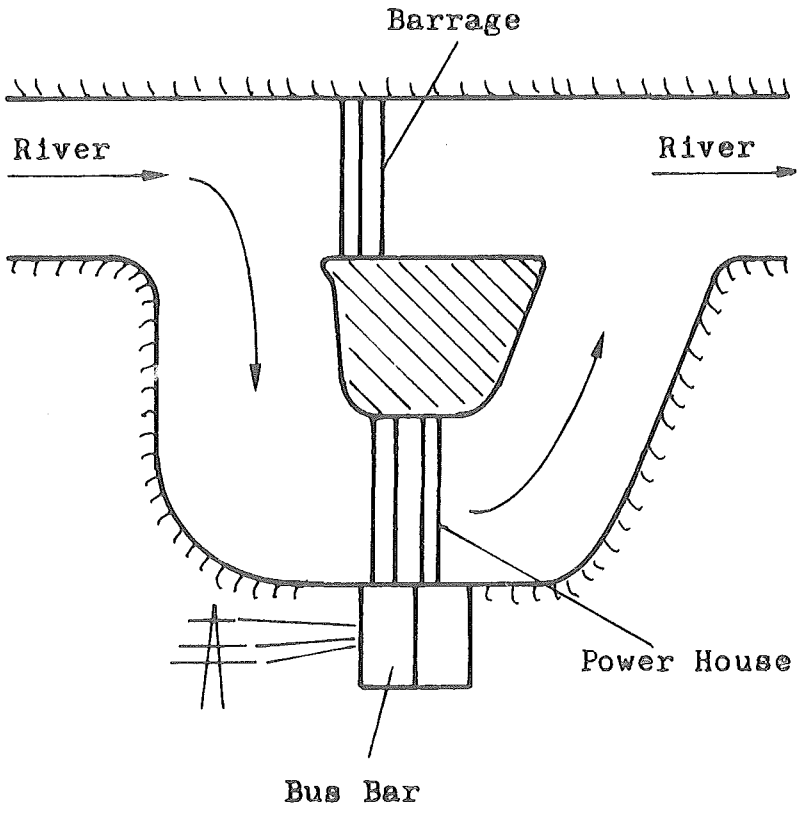


Figure 5.5: Principle of a Run-Of-River Hydroelectric Power Plant

(2) Storage Hydro Power Plant (Switzerland)
Water stored behind an artificial dam is released through turbines for electricity generation during periods of peak demand. The described system is located in the Alps near Illanz in Graubünden (Switzerland).

(3) Hydroelectric Power Plant (Japan)
The assessors indicated that the characterization does not describe a specific hydroelectric technology, but gives an estimate for a hypothetic system which represents a statistical average of a larger number of medium-size storage (except pump storage) and run-of-river power plants.

(4) Pumped Storage Power Plant (Switzerland)
Figure 5.6 shows the principle of a pumped storage operation.

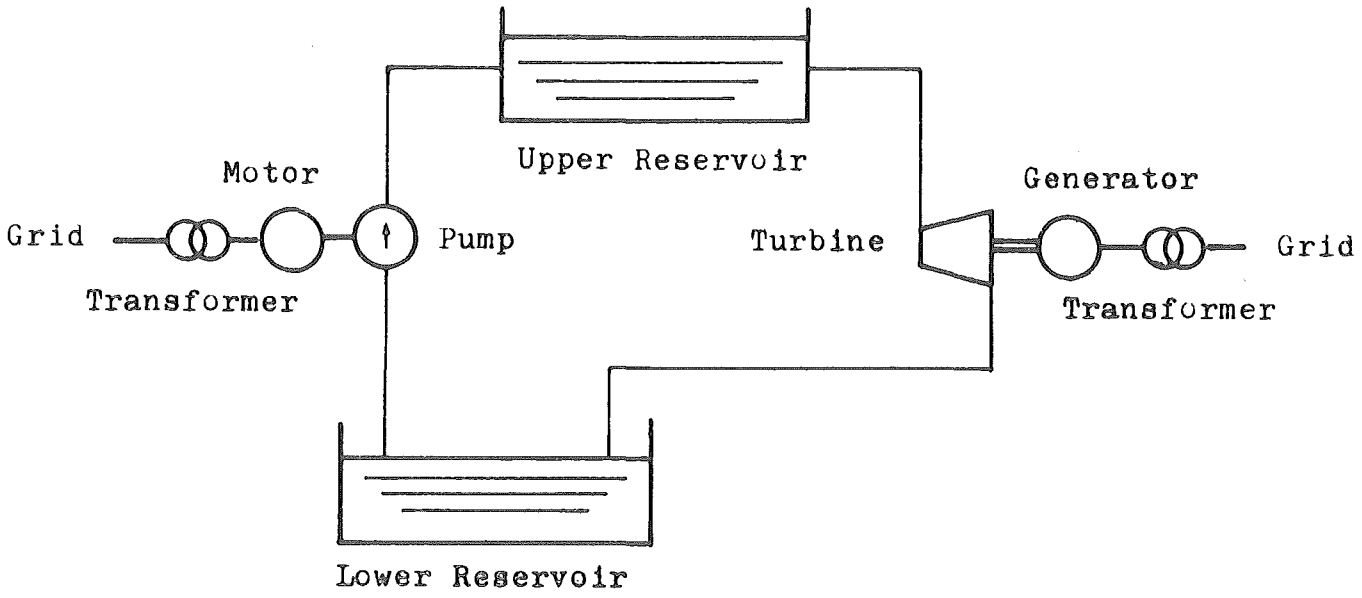


Figure 5.5: Principle of a Pumped Storage Operation

The pumped storage power plant, described for this report is installed in the Swiss Alps (Seebodenalp).

(5) Hydroelectric Power Plant: New Dams (U.S.A.). A detailed system description is not available.

TABLE 5.11: - Technical and Economic Key Data of Hydro Energy Conversion Systems

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	TJ	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
Run-Of-River Switzerland	17	c.a.	277	52	99	84	2520	83.2	←	40
Hydro Storage Switzerland	80	c.a.	1000	39.6	39.6	76	2710	89.4	←	40
Japan	25	c.a.	355	45	45	85	2378	120.8	←	60
Pumped Storage Switzerland	500	c.a.	2700	17	98	73	497	16.4	←	40
U.S.A.	100	c.a.	946		30		1500	20.24	0.33	50

Assessors

Switzerland:- Wochele, J., EIR, Würenlingen

Japan:- Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki, Japan

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory

Note:

(1) Uncertainty ranges for the data entries were not specified, except for the Capital Cost of the American hydroelectric system where a range of 650 - 3000 $/kW$_e$ was given.

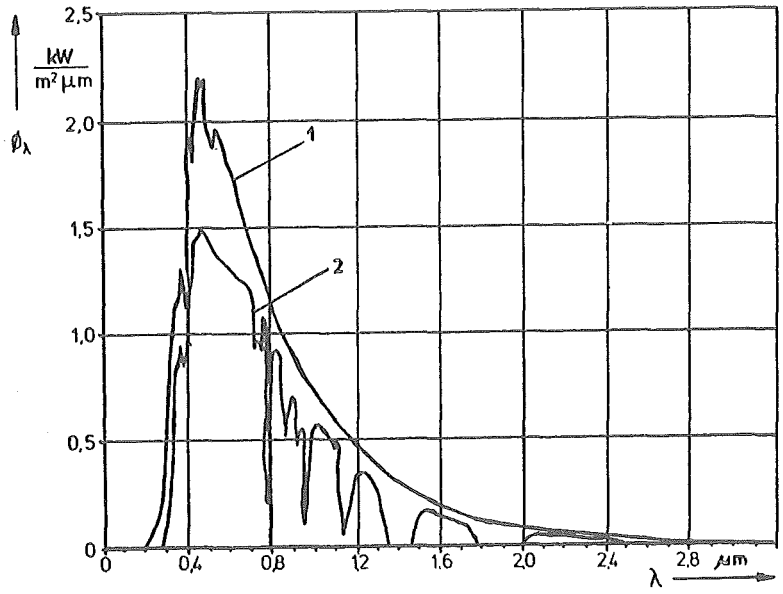
5.6 Large Solar Energy Conversion Systems

5.6.1 Introduction

The sun radiates energy in a relatively narrow band of wavelengths between 0.22 and 3.3 μm with a maximum intensity at about 0.5 μm (see Fig. 5.7).

This spectral energy distribution corresponds to a "black body" at 6000 K. (A "black body fully" is one which fully absorbs radiation of this wavelength.

At the outer limits of the earth's atmosphere, the solar radiation falling on a surface perpendicular to the sun's rays has an intensity of 1355 W/m². This quantity, known as the solar constant, is reduced by an average of 54 per cent in the earth's atmosphere, where 35 per cent is reflected back into space and 19 per cent is absorbed and then reradiated to space. The total amount of solar radiation intercepted at the surface of the earth thus is approximately $2.5 * 10^{24}$ J per year or roughly 18 000 times as much energy as is consumed in all man-made devices currently in use throughout the world.



1 extraterrestrial

2 terrestrial at sea level (sun at the zenith)

Figure 5.7: Solar Radiation Spectrum

At any given point on the earth the amount and intensity of solar radiation varies with season, latitude and atmospheric transparency. This implies several problems associated with the use of solar energy. Because of the variability of solar radiation, either energy storage or backup power is needed to provide failure-free capacity at night or when the sun is obscured. A second major problem is the low intensity of solar radiation, which requires large land areas devoted to energy collection.

In principle solar energy can be utilized in two different ways; either by thermal conversion or by the direct conversion to electrical energy in photovoltaic cells. The thermal conversion of the solar radiation may be divided into three categories:

- Low-temperature direct radiation:
  Solar radiation is intercepted on a darkened surface, where the short wave radiation is absorbed and converted into heat. The temperature of the surface will rise until it can dissipate energy at the same rate at which energy is being absorbed.

- High-temperature concentrators:
  Solar radiation is intercepted and concentrated in two-dimensional parabolic mirrors with absorber tubes running along their focal lines (so-called through-type concentrators) with absorber tubes running along their focal lines.
  For maximum efficiency, the units must be capable of following the sun, since only direct solar rays (not the diffuse radiation) will be reflected to the foci.

- Ultrahigh-temperature concentrators:
  Solar radiation is intercepted in precisely contoured parabolic reflectors, which reflect all incoming solar energy to a single point (solar furnace).

In the following, thermal and photovoltaic solar energy conversion systems for central electricity generation will be described.

5.6.2 Solar Farm Concept

Figure 5.8 shows the principle of a solar farm power plant. The solar farm power plant is equipped with a large number of through-type concentrators, in which a working fluid is heated to about 500 °C. In a heat exchanger, the heated working fluid then delivers its energy to produce process steam which drives a turbine in a thermodynamic cycle (Rankine). Solar farm systems for electricity generation reach efficiencies of about 12 to 15 per cent.

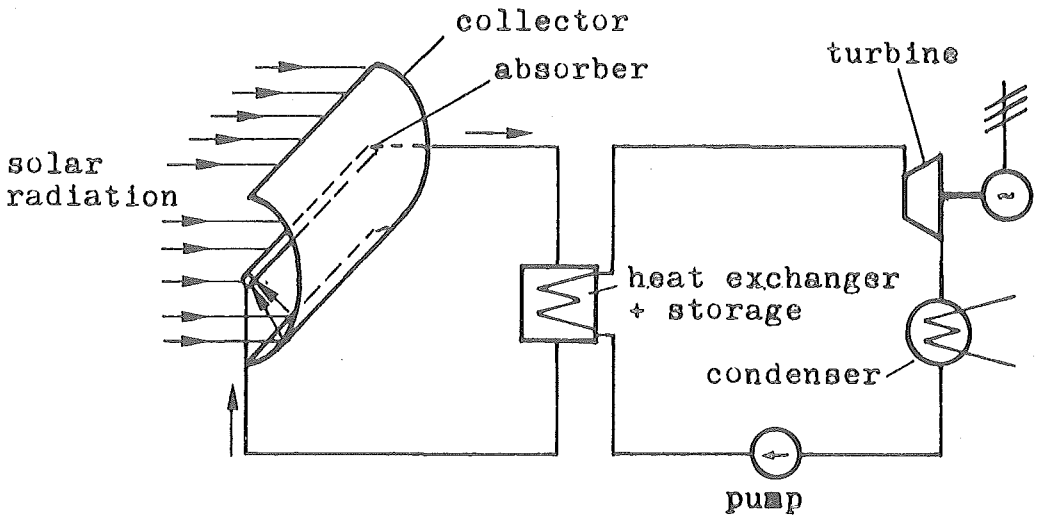


Figure 5.8: Principle of a Solar Farm Power Plant

5.6.3 Solar Tower Concept

The direct solar radiation incident on a field of heliostats (mirrors) is reflected to a central receiver (solar tower), where it is absorbed to generate temperatures up to 900 °C. The high temperature heat is transferred from the absorber to a working fluid (steam, air, helium, sodium, potassium, eutectic or salts), which drives a turbine for electricity production in a thermodynamic cycle (Rankine, Brayton, Combined Rankine/ Brayton). The principle is shown in Figure 5.9.

For this report a solar tower plant, designed for the Swiss Alps, has been characterized. It consists of 10 000 heliostats with a reflecting surface of 50 m² each. The reflected solar radiation is collected in a central receiver, where steam is generated for driving a conventional steam turbine in a Rankine steam cycle.

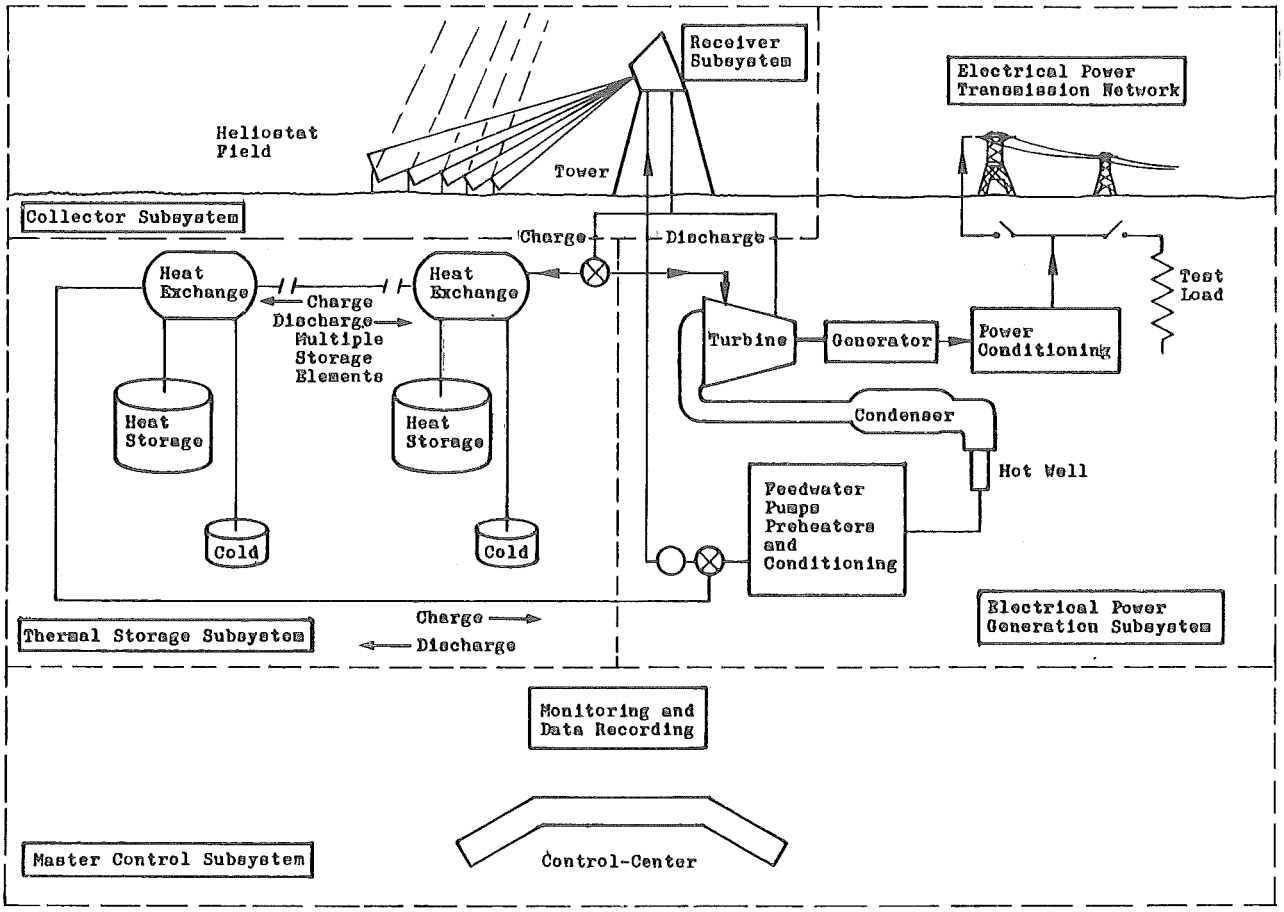


Figure 5.9: Principle of a Solar Tower Power Plant

The characteristics of the system are summarized in Table 5.12.

TABLE 5.12 - Technical and Economic Key Data of the Swiss Solar Tower System

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	TJ	%	%	%	$/kW_e$	$/kW_e$	$/GJ_e$	Yrs
Switzerland	100	1990	501	15.9	15.9	20	2254	938	←	20

Assessor

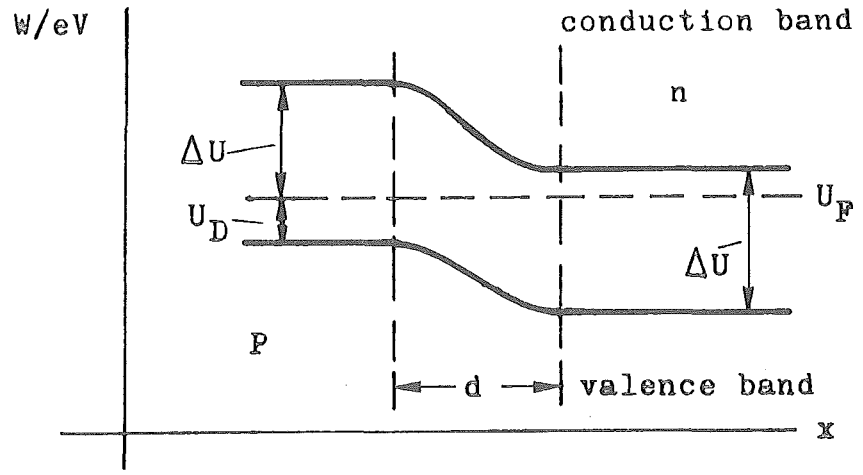
Wochele, J., EIR, Würenlingen, Switzerland

Notes:

(1) Uncertainty ranges for the data entries were not specified.

5.6.4 Central Photovoltaic Electricity Generation

The direct conversion of solar energy into electrical energy in a photo cell is based on the photovoltaic effect (first discovered by Heinrich Hertz).
The absorption of electro-magnetic radiation in a semiconductor causes an electric voltage to be generated. The principle of the conversion of light into electrical energy is shown in Figure 5.10 for a p-n semiconductor silicon photo cell.



U_F Fermi voltage
U_D diffusion voltage
U voltage difference between conduction and valence band

Figure 5.10: Band Model of a p-n Semiconductor

If the energy of a photon intercepted by the semiconductor is sufficiently high an electron is lifted from the valence band into the conduction band. For a silicon semiconductor the energetic difference between valence and conduction bands amounts to 1.4 eV. This corresponds to a wavelength of 1.11 µm. Visible light (wavelengths: 0.36 µm to 0.78 µm) can thus cause a load separation in a semiconductor photo cell, as at shorter wavelengths its energy is larger than required.

For this report a Norwegian characterization of a photovoltaic power plant has been received. The described system consists of a 10^4 m^2 area of silicon solar cells tilted at an angle of 45 °. Table 5.12 summarizes the system data.

TABLE 5.12 - Technical and Economic Key Data of a Photovoltaic Power Plant

Country	Design Capacity	First Commercial Service Year	Maximum Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_p	-	TJ_e	%	%	%	$/$kW_p$	$/$kW_p$	$/$GJ_p$	Yrs
Norway	1.41	2000	5.4	12		15	841	7	←	25

Assessor

Institute of Energy Technology, N-2007 Kjeller, Norway

Notes:

(1) The indices of the units in the summary table have the following meaning:
e = electricity
p = peak electricity

(2) TABLE 5.13 - Uncertainty Ranges

Item	Median Value	10 % Probability of Being Less Than	10 % Probability of Being Greater Than	Unit
Maximum Annual Energy Output	5.4	5.2	5.6	TJ_e
Overall Efficiency	15	14	17	%
Total Capital Cost	841	675	970	$\$/kW_p$

(3) Total Capital Cost

The total costs of the photovoltaic power plant can be broken down as follows:

Solar cells	266 (160 - 390)	$\$/kW_p$
Construction and Installation	470 (420 - 490)	$\$/kW_p$
Owner's Cost	55	$\$/kW_p$
Interest during	50 (40 - 55)	$\$/kW_p$
TOTAL	841 (675 - 970)	$\$/kW_p$

For the solar cell cost the following degression has been assumed:

1990	586 $\$/kW_p$
2000	266 $\$/kW_p$
2010	160 $\$/kW_p$
2020	107 $\$/kW_p$

5.7 Geothermal Power Plants

5.7.1 Introduction

Normally, the heat of the earth is diffuse. However, when local geological conditions (anomalies) concentrate heat energy into hot spots or thermal reservoirs, it becomes a potential energy resource. Three categories of thermal reservoirs are defined geologically:

1. Hydrothermal Reservoirs

   Hydrothermal reservoirs are the most desirable type for producing geothermal energy. These reservoirs consist of a heat source (magma) overlain by a permeable formation (aquifer) in which the ground water circulates through pore spaces. The aquifer is capped by an impermeable formation which prevents water loss.

2. Geopressured Reservoirs

   Geopressured reservoirs differ from hydrothermal reservoirs in the source of heat. They generally form in rapidly subsiding basin areas, in which an impermeable sedimentary layer caps a permeable formation (aquifer). The overburden pressure created by the compacting of the formations does not decrease in such a case as the water in the aquifers cannot leave the system through the impermeable sedimentary layer. As a result there is a sharp increase in the temperature gradient on top of the permeable formation.

3. Hot Dry Rock Reservoirs

   In a hot dry rock system no permeable aquifer overlies the heat source. Consequently, the utilization of such a reservoir requires fracturing the rock and injecting a working fluid (e.g. water) in order to transport the geothermal energy to the surface.

In the following the technical options for utilizing geothermal resources will be described.

5.7.2 Hydrothermal Power Plants

Two categories of hydrothermal or geopressured reservoirs can be distinguished, based on whether hot water or vapour dominates the reservoir. Vapour-dominated systems, such as geysers, are the most commercially attractive, but are relatively rare.

For this report the Japanese project participants assessed a geothermal binary cycle power plant utilizing a hot water dominated hydrothermal reservoir. In a first stage of the described system, natural steam is separated from the geothermal hot water which in general is partially evaporated. The separated steam drives a conventional steam turbine in a Rankine cycle. The remaining hot water transfers its energy in a subsequent heat exchanger to a low enthalpy working fluid, such as freon or isobutane, which drives a second turbine for electricity generation in a secondary thermodynamic cycle (Brayton cycle). Table 5.14 summarizes the Japanese assessment of the geothermal binary cycle power plant.

Additionally, data of an American geothermal power plant are included in table 5.14. A detailed technical description of the system like for Japanese binary cycle plant, however, has not been provided. A direct comparison of the figures in table 5.14 hence should be treated carefully.

TABLE 5.14 - Technical and Economic Key Data of a Hydrothermal Binary Cycle Power Plant

Country	Design Capacity	First Commercial Service Year	Maximim Annual Energy Output	Capacity Factor	Maximum Annual Availability	Overall Efficiency (Average Load)	Total Capital Cost	Fixed O&M Cost	Variable O&M Cost	Economic Lifetime
Unit	MW_e	-	TJ_e	%	%	%	$/kW_e	$/kW_e	$/GJ_e	Yrs
Japan	10	1990	284	90	90	8.5	3072	283.2	←	20
U.S.A.	50		1183	60	75	12	1350	28.1	0.46	30

Assessors

Japan:- Koyama, S., Kashihara, T., Endo, E., Electrotechnical Laboratory, Sakura-Mura, Ibaraki,

U.S.A.:- Bhagat, N., NCAES, Brookhaven National Laboratory

Notes:

(1) Fixed O&M Cost:

The fixed O&M cost of the Japanese system can be split in the following components:

Tax	44.4 $/kW$_e$
Drilling of additional wells	136.9 $/kW$_e$
Labour, repair, insurance, other	101.9 $/kW$_e$
TOTAL	283.2 $/kW$_e$

(2) Total Capital Cost

The differences between the presented capital cost figures occur because the American estimate (presumably) refers to a "single-cycle" (i.e. steam cycle only) geothermal power plant, while in the Japanese characterization a binary cycle power plant is considered. This supposition is strengthened by some Italian cost data for a singlecycle geothermal power plant, which is under construction at present in Italy and will be enlarged to a capacity of 250 MW by the year 1990. The capital cost figure given for this system is 2000 $/kW of which 60 % is spent for prospection and drilling, 13 % for piping, 20 % for conventional plant equipment and the remaining 5 % for reservoir studies and engineering (assessor: Giancarlo Tosato, Ente Nazionale Idrocarburi, Rome).

(3) TABLE 5.14 - Uncertainty Ranges

Country	Item	Median Value	10 % Probability of Being		Unit
			Less Than	Greater Than	
U.S.A.	Overall Efficiency	12	7	17	%
	Total Capital Cost	1350	1100	2000	$\$/kW_e$
	Fixed O&M Cost	28.1	20.0	40.0	$\$/kW_e$
	Variable O&M Cost	0.46	0.35	0.65	$\$/GJ_e$

In the Japanese characterization uncertainty ranges were not specified.

5.7.3 Hot Dry Rock Geothermal Power Plants

The utilization of hot dry rock reservoirs for geothermal energy production requires fracturing of the rock and injecting water in order to transport the geothermal heat to the surface. Fracturing the hot dry rock zone can be achieved by two different methods. One is the hydraulic fracturing method, which involves pumping water under high pressure into a well, causing the rock to crack around the borehole. The second fracturing method is nuclear fracturing in which in an array of multiple nuclear explosives serves as the fracturing agent.

For geothermal production a pair of wells (one deep and one higher well) is drilled in a cracked, hot dry rock zone. Cool water is pumped into the deeper well and circulated through the hot cracked zone into the higher well where it returns to the surface. If the water returns to the surface as steam, the steam can be used to drive a turbine in a Rankine cycle. If it returns as hot water, the heat energy can be extracted through a heat exchanger and transferred to a low enthalpy working fluid, like Freon, which drives a turbine for electricity production in a Brayton cycle. A combined process, as described in the preceding section, is likewise possible, if the injected water is heated to wet steam which allows a steam/hot water separation. In every case, the re-cooled water is pumped down the deeper well again to be reheated, thus effecting a closed circulation system /5.1/.

5.8 References

/5.1/ Energy Alternatives - A Comparative Analysis Science and Public Policy Program, University of Oklahoma, Norman, 1975

/5.2/ Pollutant Releases, Resource Requirements, Costs and Efficiencies of Selected New Energy Technologies, Teknekron Inc., Dec. 1975

/5.3/ Romanelli, P.J., "Electrical Generating Equipment and Electric Utility Requirements for High Power Wind Generator Systems", 10th Intersociety Energy Conversion Engineering Conference, IEEE, Aug. 1975

/5.4/ Development of Construction Plans for the GROWIAN System, Large Scale Wind Energy Convertor, Status Report No. ET 40887

/5.5/ Boeing Engineering & Construction Company, MOD-2 Wind Turbine System, Concept and Preliminaries, Design Report, Volume II: Detailed Report, DOE/NASA/0002-80/2, NA 617 CR-159609, July 1979

6. RESIDENTIAL AND COMMERCIAL END-USE

6.1 Criteria for Comparison of Selected R&C Space Heat and Warm Water Generating Technologies

It is difficult to carry out accurate technical and economic comparisons of space heating and water heating technologies, because a wide variety of systems are available. Interpretation of the differences in technologies for different countries (Central, North and South Europe, North America, and Asia) is even more difficult.

The major reasons for these differences can be attributed to the type of house in which the space heating and/or water heating system is installed: i.e. the size (single family, two-family, multi-family home, commercial house etc.), the level of insulation and the meteorological conditions at the location. Consequently the technical design and costs vary considerably.

An earlier study, completed in 1980 for the IEA Energy Systems Analysis Project, compared the components of 26 different space heating systems for two standardized house types and four fixed insulation levels (Ref. 6.1). The study shows the variations for the characterization, but does not present enough detail to determine the state of development in all countries.

The following examination of space heating and water heating systems considers the device separate from the house itself, because of the problem inherent to the configuration of houses (size, insulation level, location). Descriptions of the characteristics of individual houses are not contained in this summary.

It is not possible to list all the variants which exist so this chapter focusses on heat pump systems, which are expected to play an important role in the future R & C space and water heat supply.

The workshop, which reviewed the questionnaires, designed the following list of indicators for space heating and water heating systems:

DESIGN CAPACITY (OUTPUT PEAK CAPACITY)
FIRST COMMERCIAL SERVICE YEAR
ANNUAL SPACE HEATING DEMAND
ANNUAL WATER HEATING DEMAND
BACKUP FRACTION (if required)
ANNUAL OVERALL EFFICIENCY
ECONOMIC LIFETIME
TOTAL CAPITAL COST PER UNIT DESIGN CAPACITY
FIXED OPERATING AND MAINTENANCE COST PER UNIT DESIGN CAPACITY

These are the standard indicators discussed in the following sections; other factors for system comparisons are included, where necessary.

It should be noted that the system comparisons presented here go beyond the review of heat pump technologies previously organized by the IEA secretariat (Ref. 6.2). The comparisons in this chapter also include the installation cost of the control and distribution system, additional constructional expenses (e.g. for fuel storage room, chimney, etc.) and costs for the heat source preparation as well as those considered in Ref. 6.2. Where possible, however, a cost disaggregation is given which enables a comparison to be made with the figures presented in the Final Report of the IEA Heat Pump Technology Review. The comparisons which have been made show good agreement after taking into account small deviations arising from the inherent uncertainty in assessing such characteristics.

6.2 Heat Pumps

Heat pumps raise low-temperature ambient energy ("anergy") to a higher temperature level using some auxiliary energy input ("exergy"). This principle has been applied for many years in

space heating, space cooling including dehumidifying, and water heating. The technical description of heat pump systems given in the following section focuses on heating but the principles are applicable to the other applications.

The basic difference between space heat supplied by conventional boilers and that supplied by heat pumps is illustrated in Figure 6.1. The mixture of anergy and exergy which is provided for space heating results from the consumption of a certain amount of exergy for a conventional boiler. A much smaller amount of exergy is consumed, in the heat pump and this exergy combined with ambient energy (anergy) produces an equal amount of space heat.

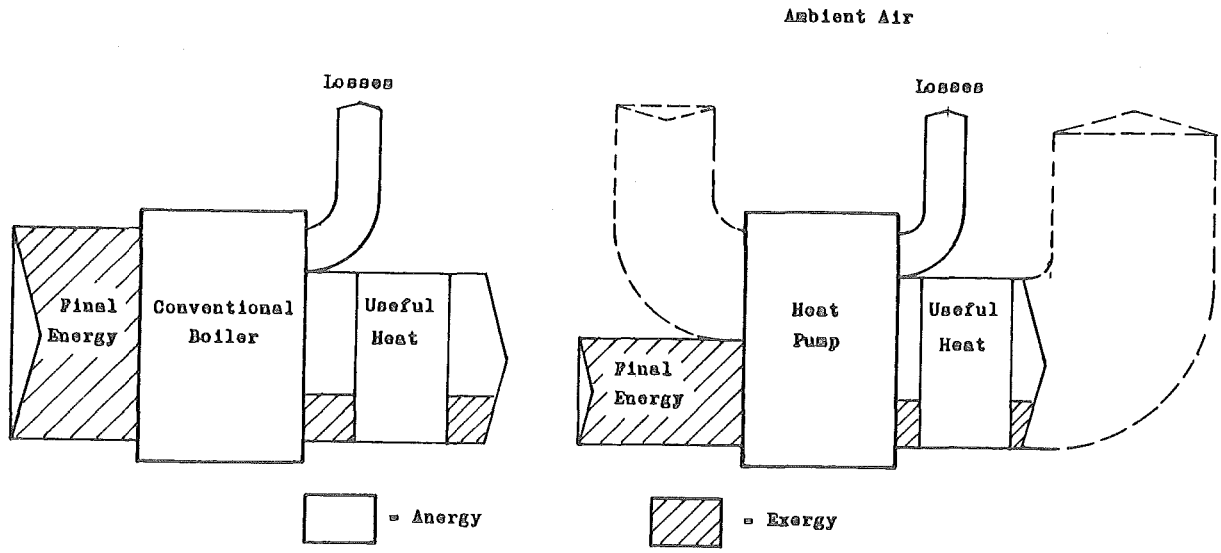


Figure 6.1: Exergy/Anergy Flows for Space Heat Generation in Conventional boilers and Heat Pumps

Several processes have been chosen in practice for heat pump systems (Fig. 6.2).

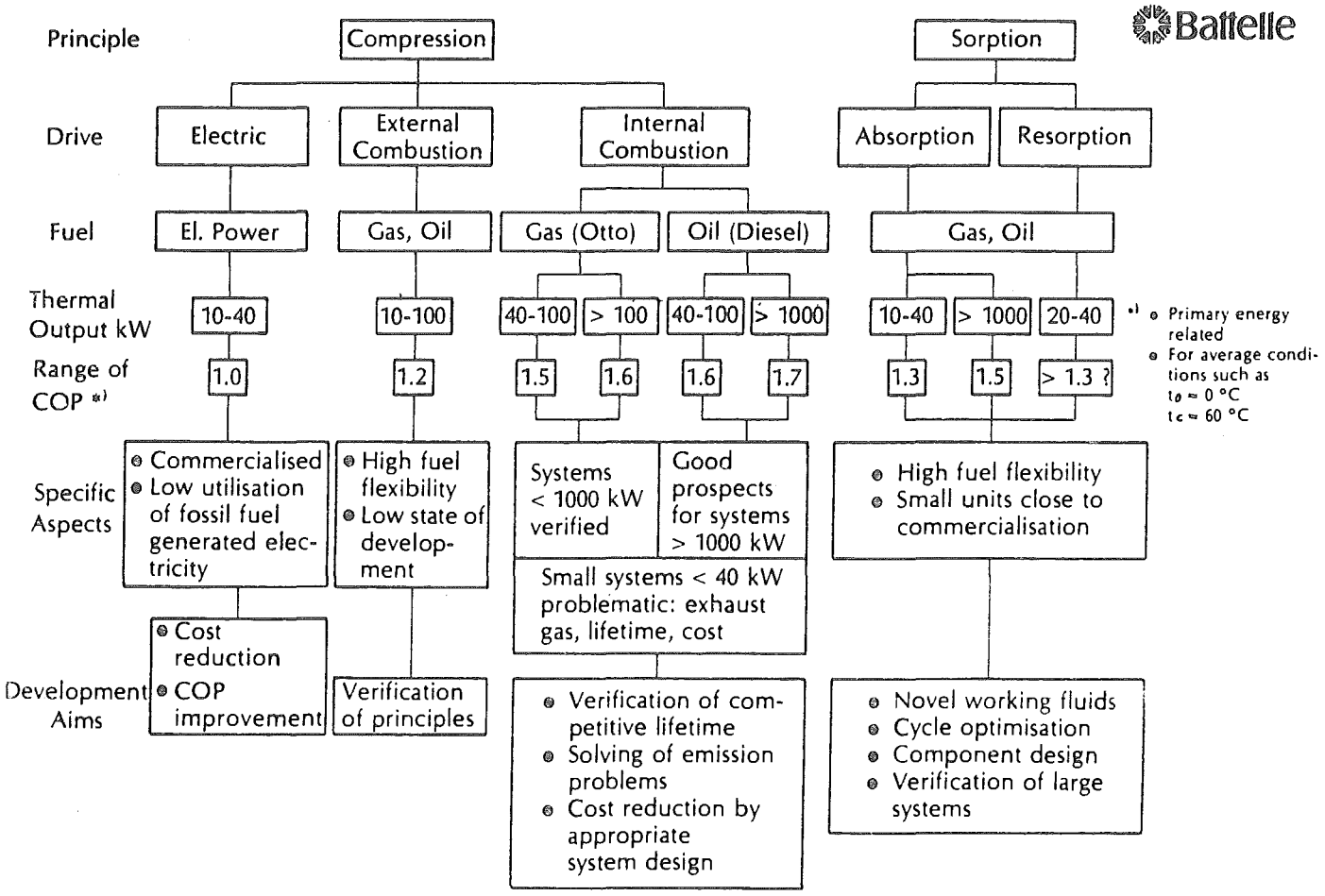


Figure 6.2: Schematic of R&D Trends

6.2.1 Technical Description

Not all suggested processes have achieved a technical or a market breakthrough. Compression heat pumps show the highest state of development and commercialization today. Absorption heat pumps have not yet penetrated significantly into the space heating market, but several research projects have been launched and small scale units are close to commercialization. Independent of the working system, a heat supply source is required for any heat pump process. The principal heat sources are displayed in Figure 6.3.

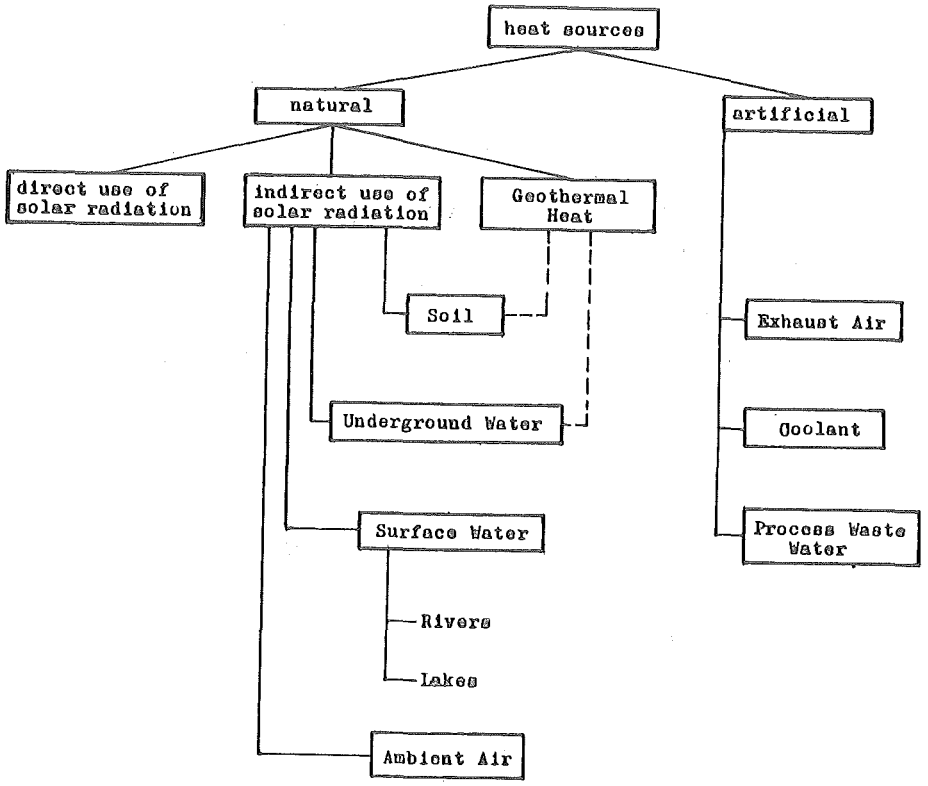


Figure 6.3: Heat Sources for Heat Pumps

Air:

In theory, it is possible to extract any desired amount of heat from the air, anywhere in the world. If 1 m^3 of dry air is cooled by one degree Celcius approximately 0.35 Wh of energy can be extracted. Consequently large volumes of air have to be moved, the dimensions of the cooling apparatus are relatively large and, in general, relatively large amounts of mechanical energy are required for the air fans. A further disadvantage is the divergence of the heat demand profile and the air temperature profile during the year (see Fig. 6.4), showing that heat demand is highest when ambient air temperatures are lowest. This can lead to complications if the moisture in the air freezes on the heat pump's coils and reduces its performance.

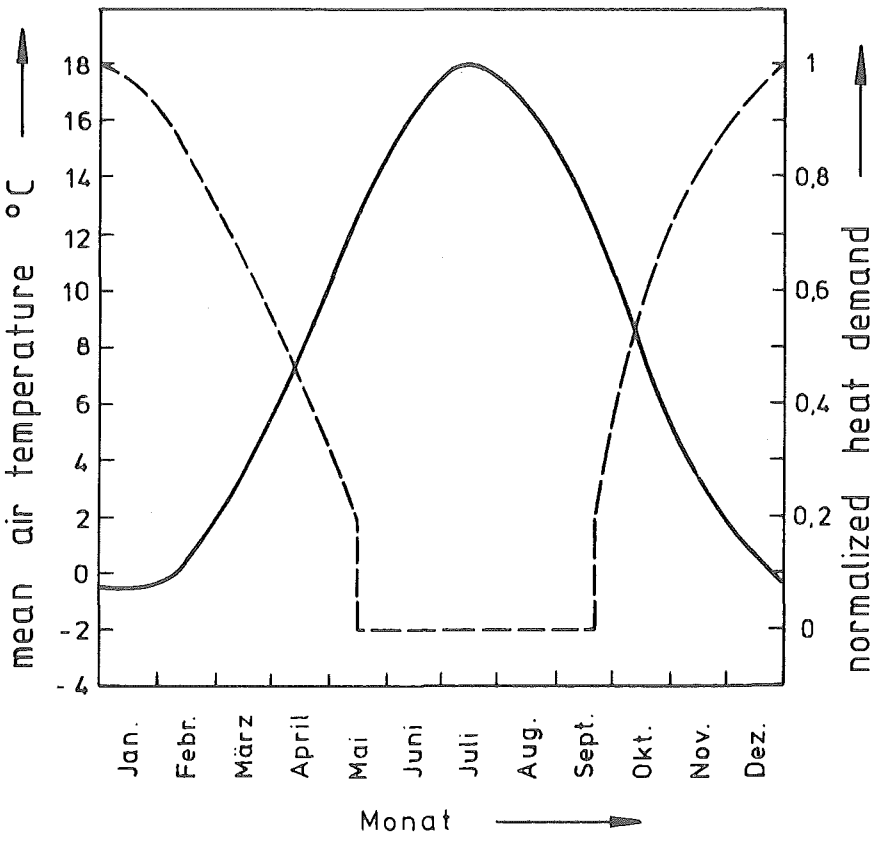


Figure 6.4: Annual Curves for Air Temperature and Heat Demand in Berlin

Soil:

Heat from the soil can be extracted with large size heat exchangers which are buried in the soil. The burial depth of the tubes is generally between 1 and 2 m, the distance between adjacent tubes varies between 0.5 and 1.5 m, depending on local circumstances. The capacity of the soil heat exchanger is a function of the duration of the heat extraction and of the soil temperature; in general, the capacity is between 15 and 40 W/m². As a general rule, the dimensions of a soil heat exchanger have to be about 2 to 4 times larger than the dimensions of the area to be heated. The operation of the soil heat exchanger involves no technical problems. Negative impacts upon the environment appear to be limited to the vegetation directly above the heat exchanger. The vegeation's growth lags a few weeks behind neighbouring areas.

Underground Water:

Underground water is an important heat source, because of its relatively high temperature level. Figure 6.5 demonstrates that the seasonal alterations of the temperature are very small at a depth of about 7 m and more.

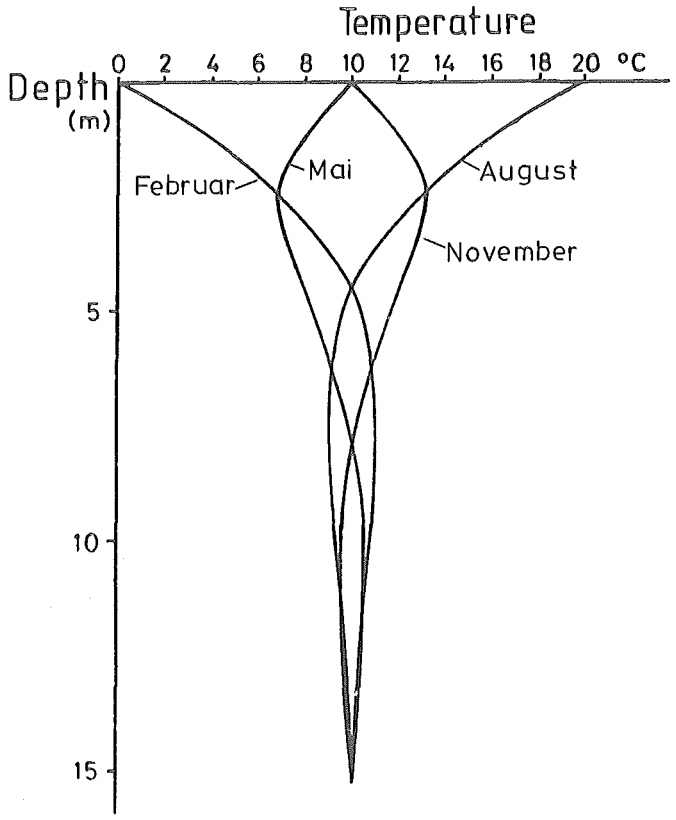


Figure 6.5: Temperature Profiles in the Soil and Underground Water (Example for Western Europe)

The average temperature level lies within the small range of 8 to 10 °C. Because of this characteristic, heat pumps using underground water are very effective, especially for winter operations. The utilization of underground water as a heat source naturally depends upon the amount available and the quality of the water. The water availability, in particular, is restricted by the number and depth of the required drill-holes and legal restrictions on the use of underground water.

Surface Water:

The heat potential of rivers and lakes is very large; the heat potential of the Rhine at Düsseldorf, for instance, amounts to approximately 27000 MW, even during the winter. This amount exceeds the demand for space heat for the city of Düsseldorf by a factor of 16. Even small rivers have, in general, a satisfactory heat supply potential. However, the use of this heat source will be only be economical, if the movement of heat and water is restricted to short distances, and if the feedwater and backflow water installations can be built at low cost. Another possible problem is existing pollution of the water feed. Depending on the type of pollution, special materials may be required for the heat exchangers to minimize corrosion and this would raise costs. The exchanger may need periodic cleaning, which would increase the operating & maintainance costs.

6.2.2 Design

The compression heat pump consists essentially of a compressor (driven by an electric motor or a combustion engine) a condenser, an evaporator, and an expansion valve between condenser and evaporator (Figure 6.6).

The working fluid leaving the evaporator is usually a vapour which is compressed using mechanical energy. The vapour temperature rises during compression and it enters the condenser under high pressure. The heat extracted from the vapour in the condenser and passed to the space to be heated causes the vapour to liquefy. Most of the heat transferred is the heat of condensation. The liquid passes to the expansion valve, where the pressure and temperature fall to low levels. Usually some of the liquid evaporates during this expansion, but most of the evaporation takes place in the evaporator. The heat necessary for evaporation is extracted from the environment. The working fluid which leaves the evaporator is then compressed and the whole cycle starts again. Thus, heat is "pumped" from the environment around the evaporator to the area surrounding the condenser.

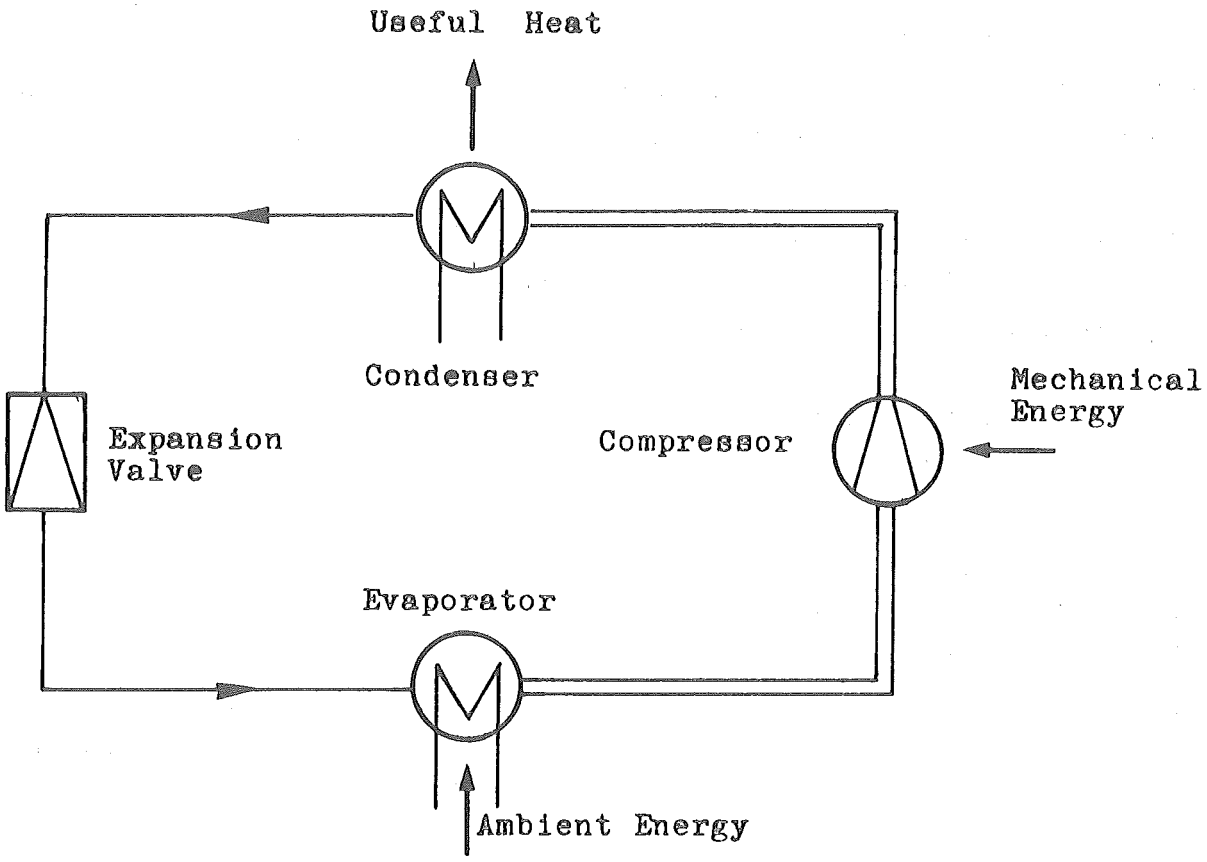


Figure 6.6: Schematic of Compression Heat Pump (Diesel, Gas, Electric Rankine)

In the case of an absorption heat pump, the process of feeding the compressor and compressing the fluid is achieved by a second cycle containing a blend of certain absorption and working fluids in the absorber and generator (Figure 6.7).

The energy required by the absorption cycle solvent pump is small compared with that required by the pump for the compression heat pump cycle. This is because the compression cycle pump operates on vapour and the absorption pump operates on liquid. The other components in the absorption cycle are similar to those for the compression heat pump cycle. The absorption heat pump generates useful heat at two places, at the condenser and the absorber.

Any absorption cycle requires a high temperature source (about 100 °C to 200 °C) to supply heat to the generator and generate the working fluid for the main part of the circuit. Hence this cycle requires both mechanical energy, for the pump, and a high temperature heat source for the generator; although the latter is small compared with useful heat obtained. At the present state of development, the coefficient of performance (see next section "Efficiences") of the absorption cycle are substantially lower than for the compression cycle.

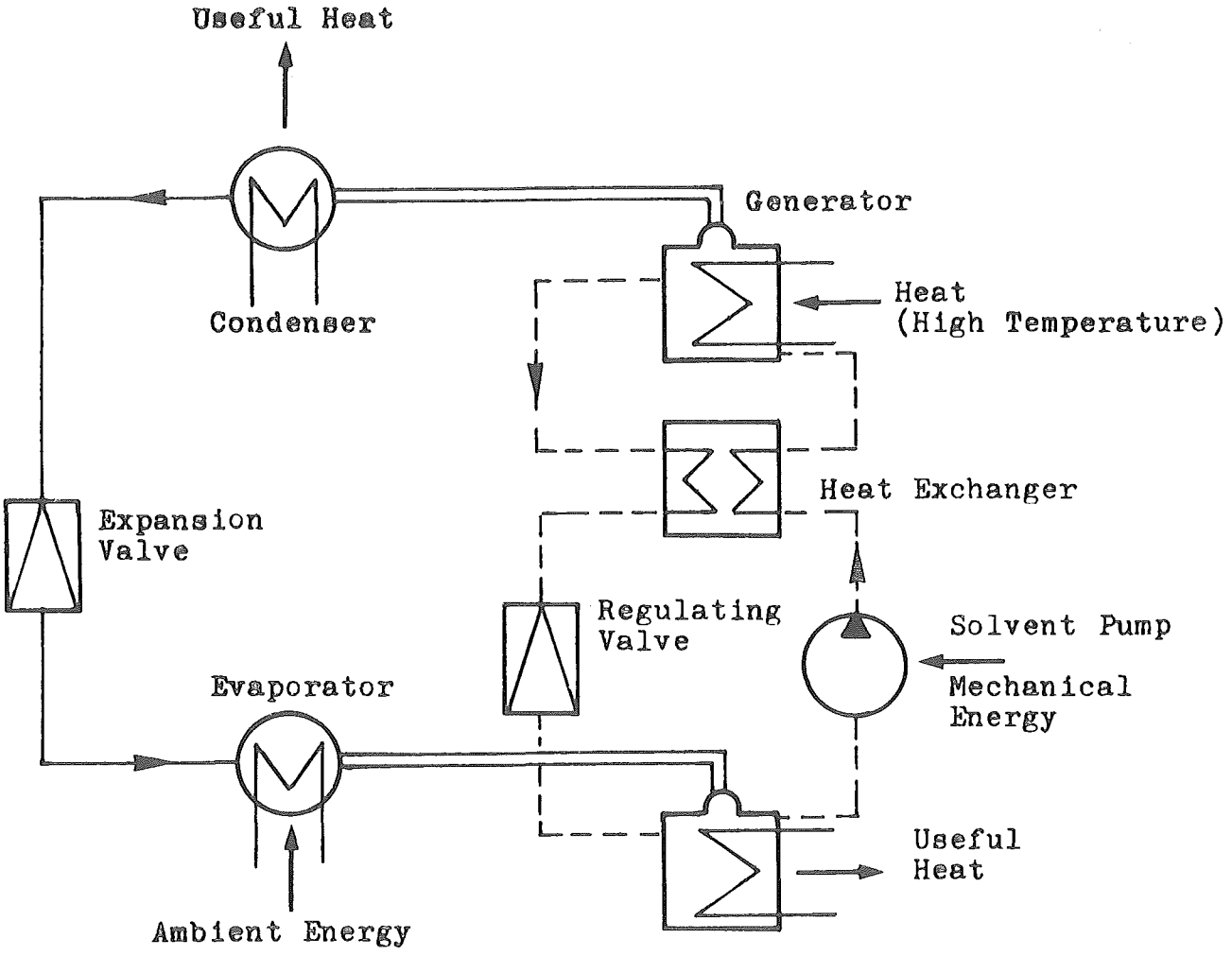


Figure 6.7: Schematic of Absorption Heat Pump

A problem in the absorption heat pump development exists in the selection of appropriate working and absorption fluids. The most common pairs are: ammonia/water and water/lithium bromide. Other pairs of fluids are subject of research, e.g. methanol/lithium bromide.

Efficiencies:

Heat pumps represent technologies which contribute to the more effective use of energy or to energy conservation. An interesting indicator for comparisons of how "rational" energy is used is the ratio of the heat supplied over the energy inputs into the system. Various ratios can be defined and compared. For the electrical compression heat pumps, the ratio of the condensor capacity, Q_K, relative to the electrical energy input, N, is often used. For combustive compression and absorption heat pumps, the ratio of the heat supplied, Q_N, relative to the energy input of the machine that drives the compressor, Q_{EE}, is mostly used.
For general comparisons of the performance of various systems it is convenient to adopt the "mean coefficient of performance", defined as the supplied heat energy, Q_N, over the primary energy input, Q_{PE}. Figure 6.8 summarizes the various indicators.

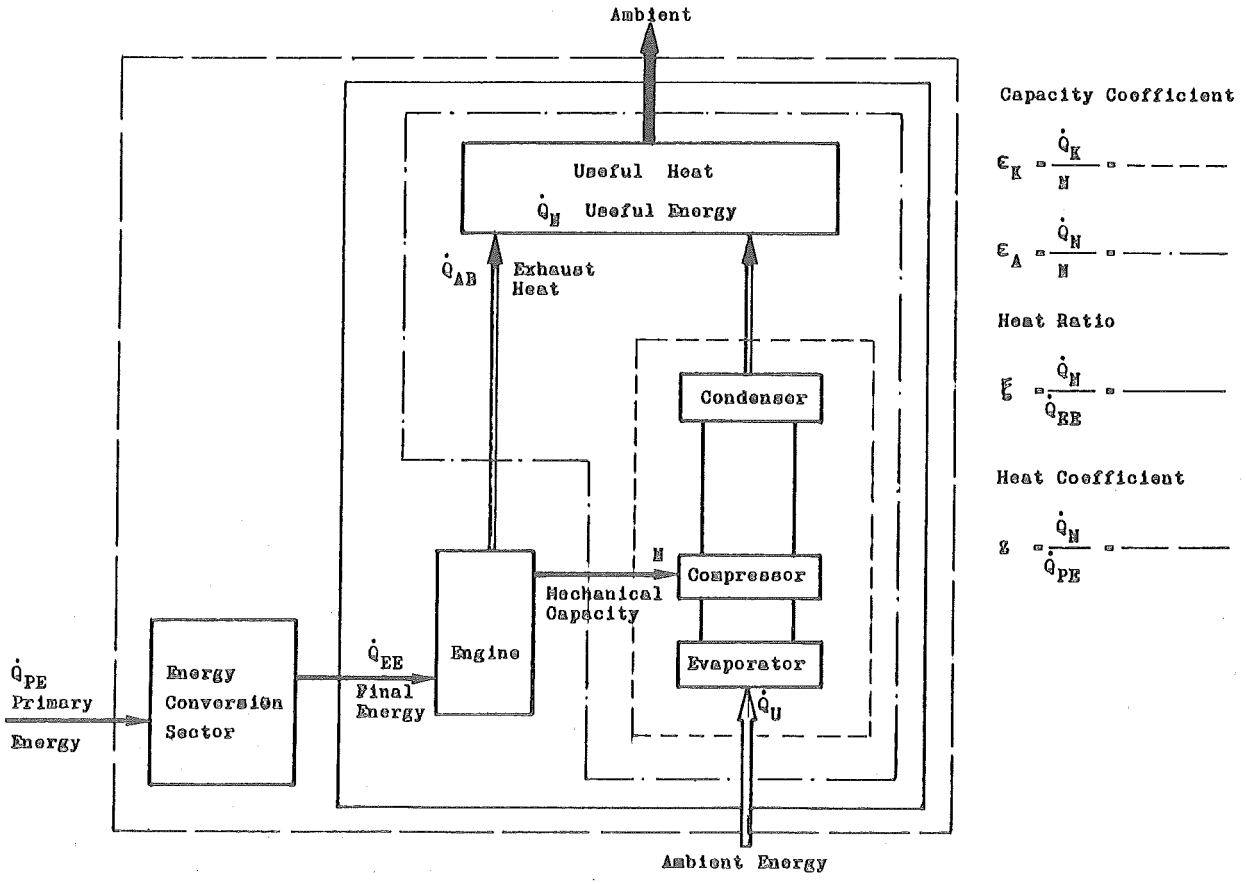


Figure 6.8: Comparison of Various Heat Pump Indicators

The mean coefficient of performance is averaged over the whole year and does not take into account seasonal variations. A more useful indicator for the energy conservation potential is the seasonal performance factor. This indicator is a function of the ambient air temperative frequency distribution, and therefore is a function of the location. The practical seasonal performance factor is also greatly influenced by efficiency fall-offs (as compared to ideal values) caused by operating the heat pump above or below the design point (Figure 6.9).

Battelle

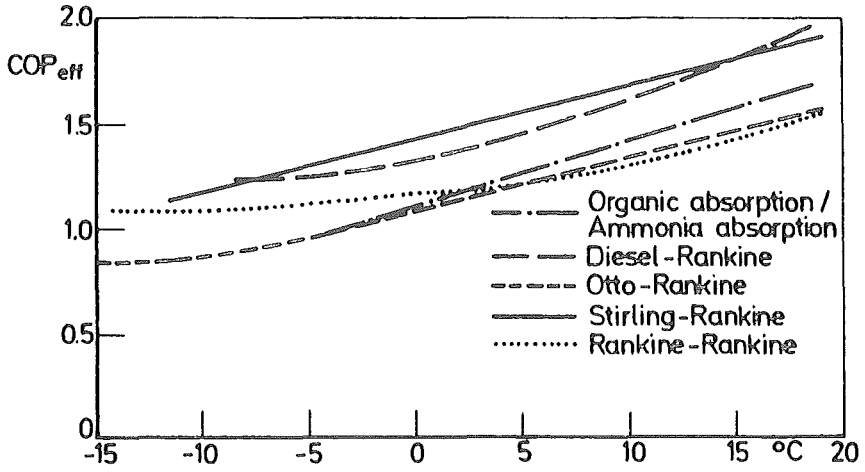


Figure 6.9: COP_{eff} of Air Source Heat Pumps (auxiliaries excluded)

6.2.3 Operation

The heat pump performance changes with changes to the difference in temperature between the space being heated and the heat pump's source of heat. Generally the space is heated to about 20 °C. If the source of heat for the pump is the outside air, then a fall in that air temperature will result in a reduction in output and a reduction in the coefficient of performance. The greater the temperature difference, the greater are the reductions. At some point the pump will deliver no heat. Naturally, a fall in outside temperature will call for more heat to be supplied by the pump to compensate for the increased heat loss through the outside walls and roof of space being heated. The combination of decreasing heat pump capacity and extra heat requirement will eventually cause the heated space to fall below 20 °C as the outside temperature falls.

A heat pump designed for the coldest day follows a progressive curve for the heat output when temperatures rise (see Figure 6.10).

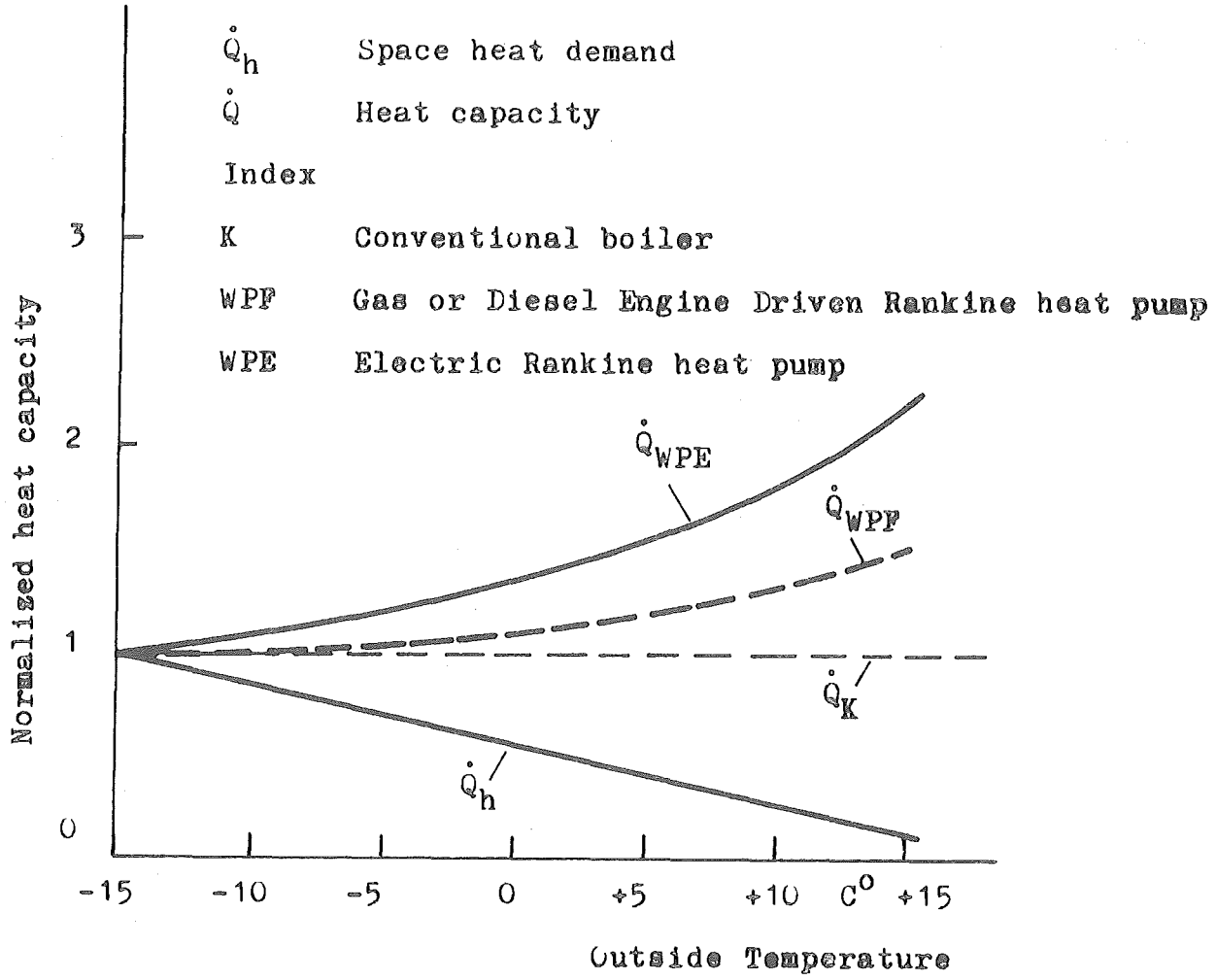


Figure 6.10: Schematic of Heat Capacity and Space Heat Demand as Function of Outside Temperature

Heat pumps which are driven by engines have a smaller increase is output as the outside temperature rises, since an essential part of the heat is taken from the engine's waste heat.

In order to avoid designing heat pumps for the coldest day (which requires complicated control systems) bivalent heat pump systems have been developed. Besides the heat pump itself a second conventional system or back-up system is used, which at low outside temperatures complements the output of the heat pump (parallel operation) or replaces it fully (alterna-

tive operation). The back-up system should not draw on central supply systems, like electric systems, in order to avoid peak demand additions. As for systems without back-up, i.e. monovalent systems, the heat demand is supplied solely by the heat pump. It must be designed for the coldest day.

Figure 6.11 shows the schematic of a monovalent combustion heat pump using natural gas as the only fuel.

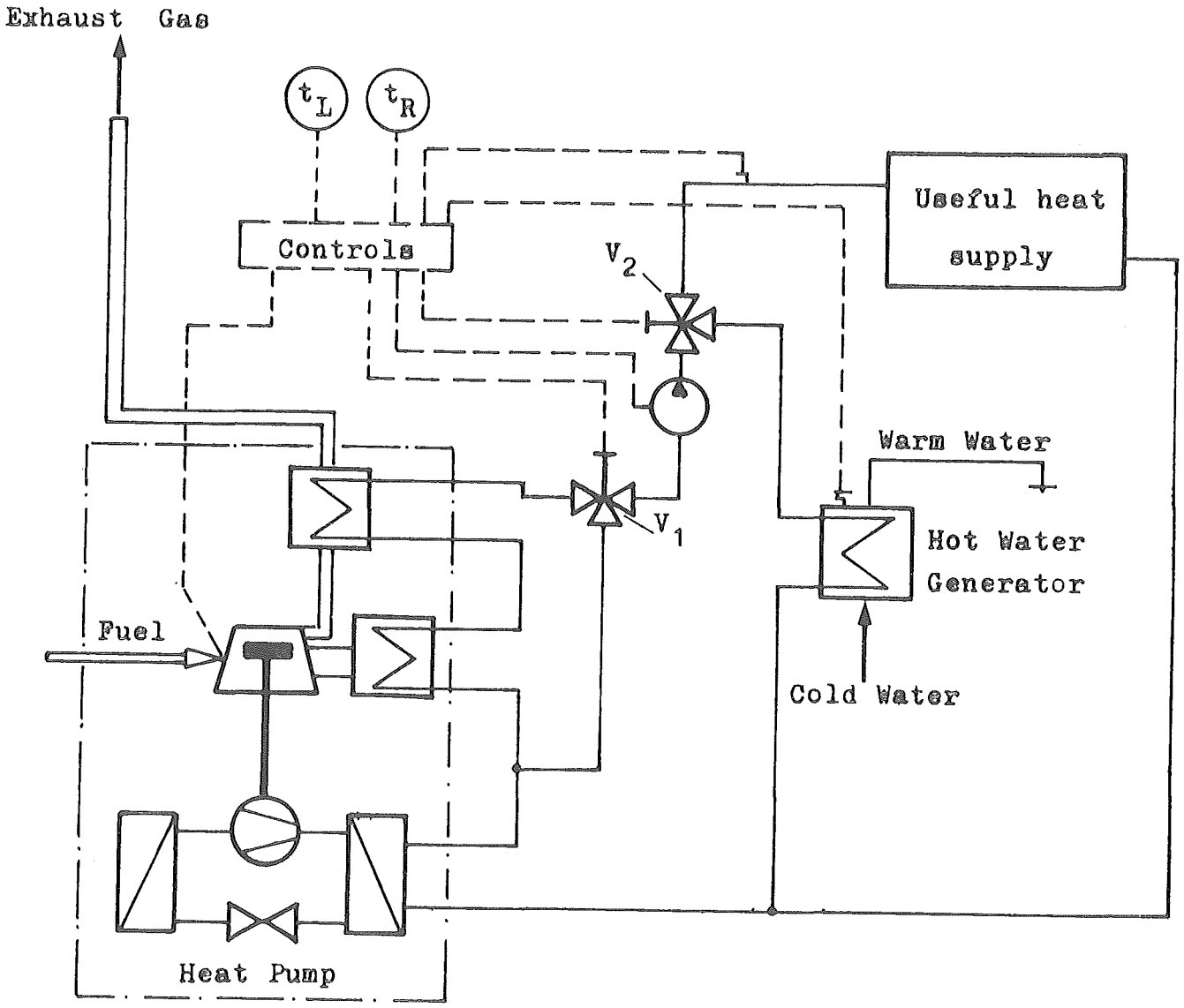


Figure 6.11: Schematic of Monovalent Gas-Rankine Water/Water Heat Pump

The schematic of a bivalent electric driven heat pump with an oil back-up system is shown in Figure 6.12. The annual heating demand and the heat distribution for the heat pump and the oil back-up system are displayed in Figure 6.13.

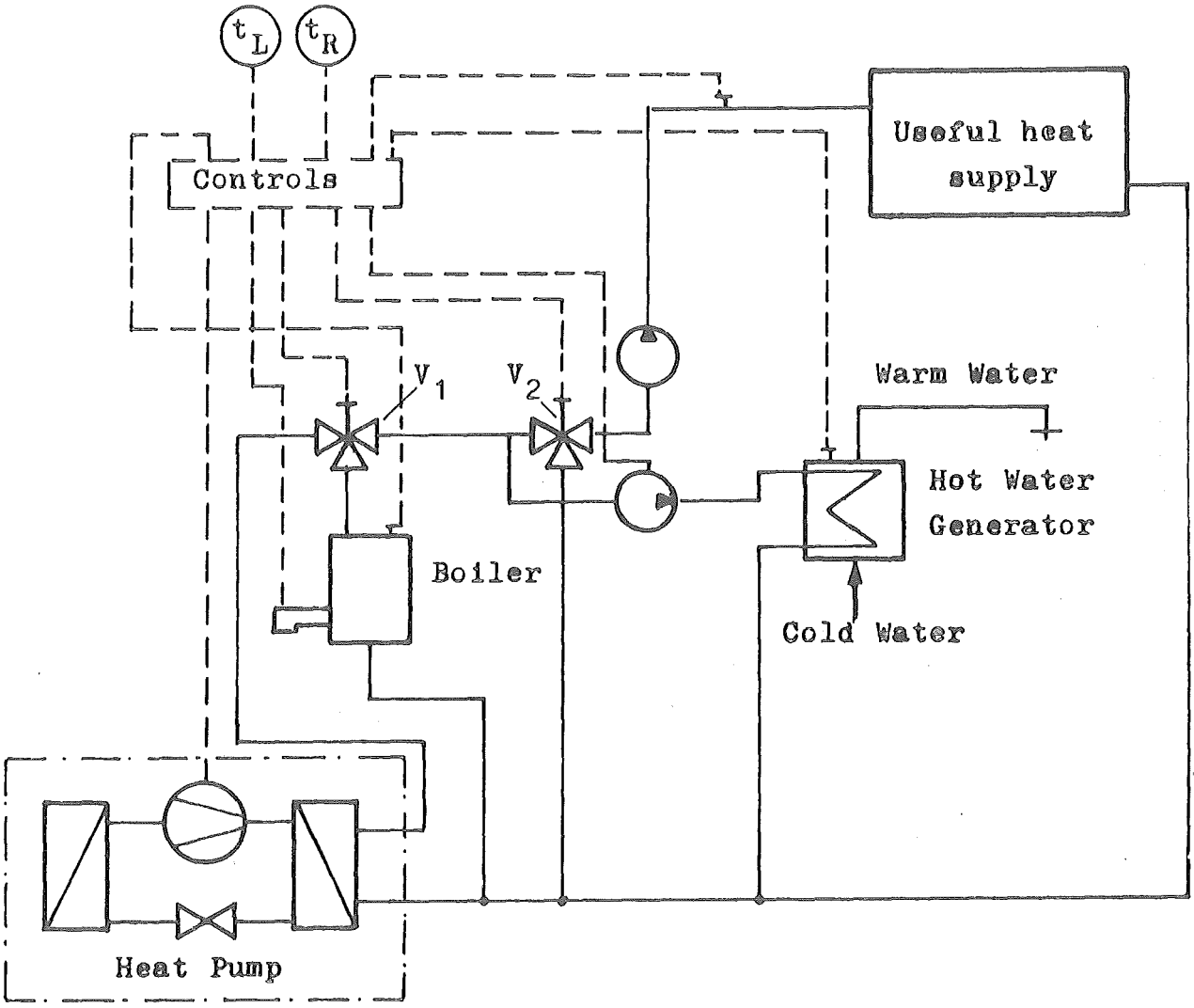


Figure 6.12: Schematic of Bivalent Electric Rankine Heat Pump

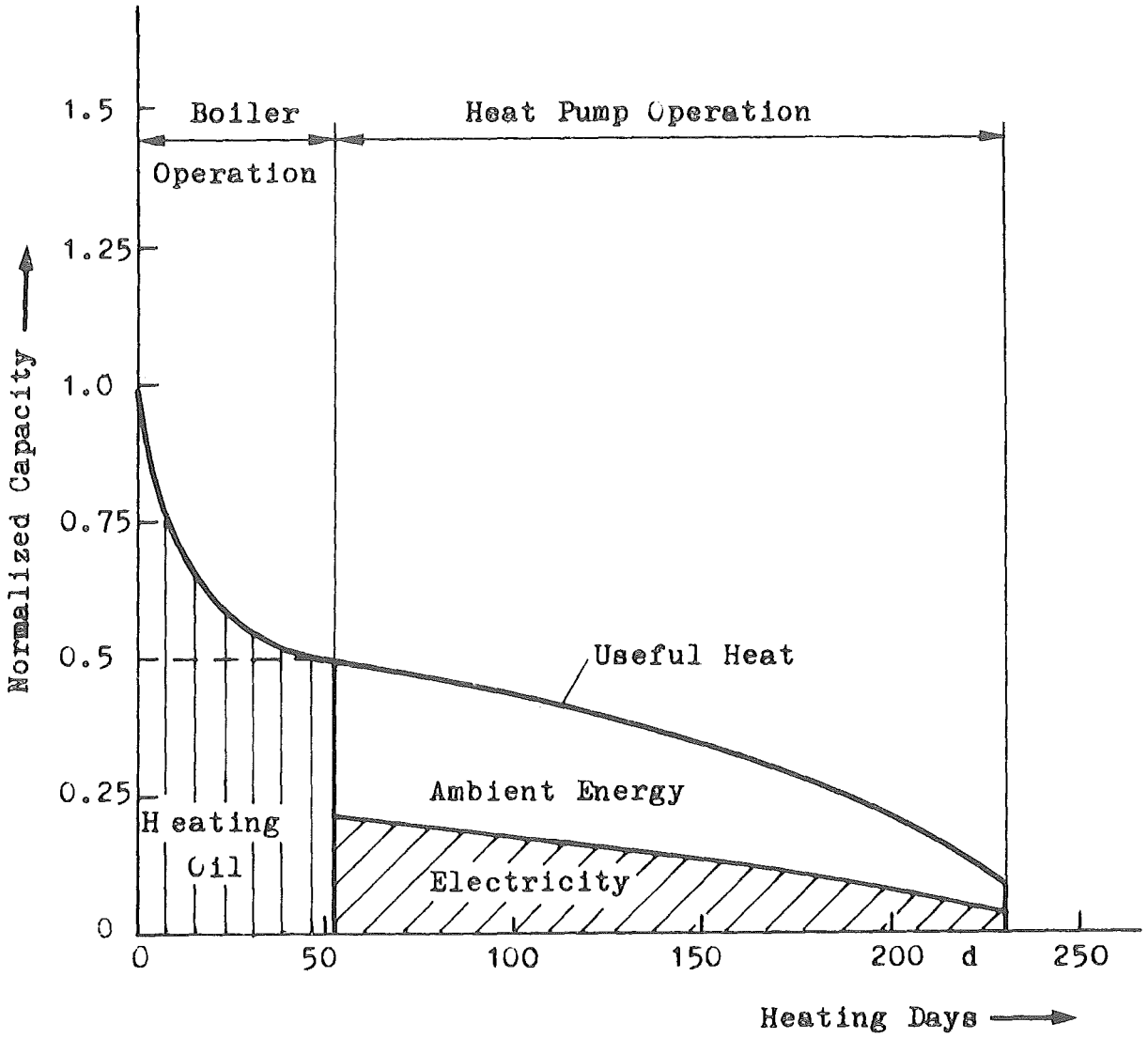


Figure 6.13: Annual Diagram of Heat Demand

6.2.4 System Comparison

Typical sizes of heat pumps which have been used in several countries are given in Figure 6.14.

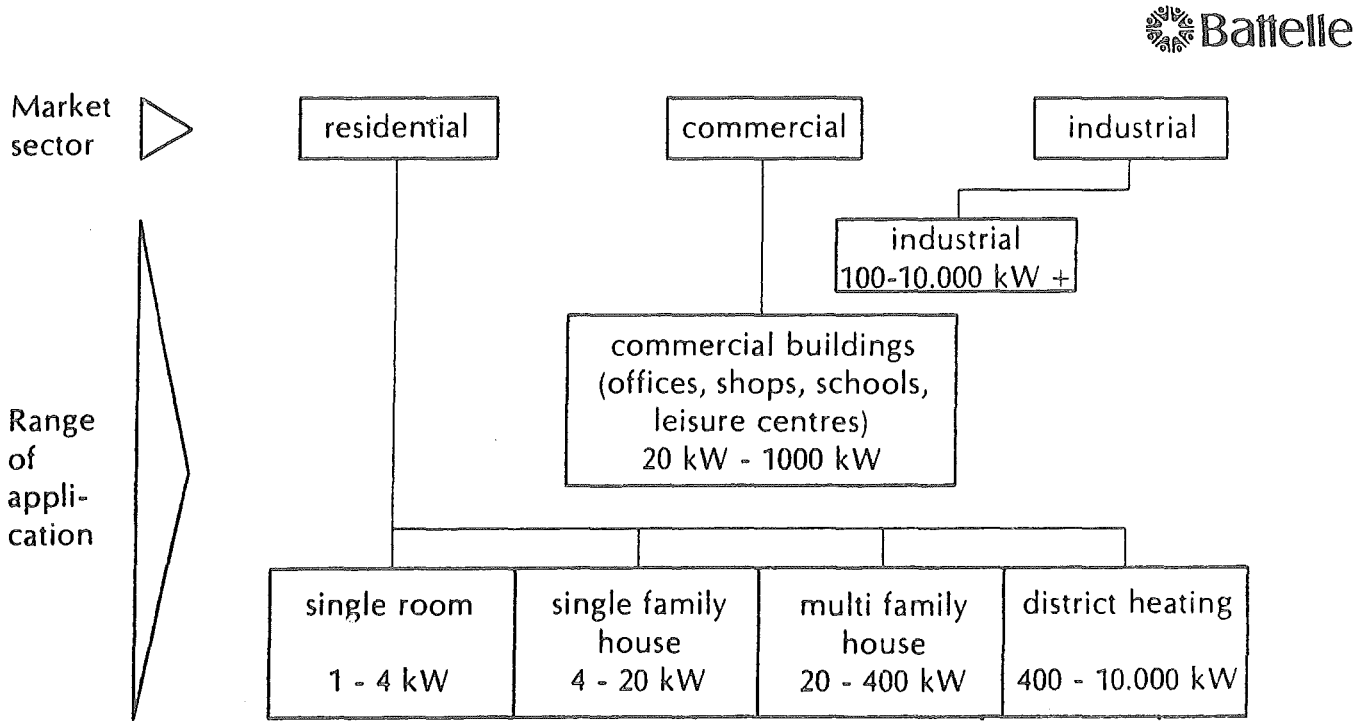


Figure 6.14: Classification of Systems by Application and Size (Thermal Output)

The heat pumps which have been examined in the context of the current project are grouped in order of capacity size for applications in:

(i) single-family houses,
(ii) two-family houses,
(iii) multi-family houses/commercial buildings.

The technical and cost parameters for these three groups are displayed in tables 6.1 to 6.3. Note that several of the heat pumps supply both space heat and water heat, while others supply space heat only.

TABLE 6.1 - Heat Pumps for Single-Family Houses
Capacity Range 6-15 KW

NO.	SYSTEM	OPERATIONAL MODE	HEAT SOURCE/ HEAT DISTRIBUTION	LOCATION	DESIGN CAPACITY	FIRST COMMERCIAL SERVICE YEAR	ANNUAL SPACE HEATING DEMAND	ANNUAL WATER HEATING DEMAND	BACKUP FRACTION	ANNUAL OVERALL EFFICIENCY	ECONOMIC LIFETIME	TOTAL CAPITAL COST	TOTAL FIXED O&M COST
					kW		MWh	MWh	%	%	yrs	$/kW	$/kW
1	Electric Compression	monovalent	Soil/Water	Belgium	6	e.	→	12.6	'/.	210	10	2430	29
2	Electric Compression	bivalent Electric Backup	Air/Air	Belgium	6	e.	→	12.6	n.a.	135	15	1080	43
3	Electric Compression	bivalent Electric Backup	Air/Water	Denmark	6	e.	13	3.6	10	195	20	1350	15
4	Electric Compression	monovalent	Soil/Water	Denmark	6	e.	13	3.6	'/.	220	20	1950	15
5	Gas Absorption	monovalent	Air/Water	United Kingdom	8	1985	15	'/.	'/.	120	20	750*	90
6	Electric Compression	bivalent Electric Backup	Air/Water	Denmark	9	e.	22.5	3.6	10	195	20	1100	10
7	Electric Compression	monovalent	Soil/Water	Denmark	9	e.	22.5	3.6	'/.	220	20	1610	10
8	Electric Compression	bivalent Oil Backup	Air/Water	Switzerland	10.6	e.	15.4	'/.	50	HP 250 BU 80	20	1840	46
9	Electric Compression	monovalent	Soil/Water	Switzerland	10.6	e.	15.4	'/.	'/.	300	18	1840	46
10	Electric Compression	bivalent Oil 8ackup	Air/Water	Germany	15	e.	22.5	3	30	HP 300 BU 72	20	880	26
11	Electric Compression	monovalent	Water/Water	Germany	15	e.	22.5	3	'/.	330	20	950	29
12	Gas Compression	monovalent	Water/Water	Germany	15	e.	22.5	3	'/.	150	15	1230	37
13	Diesel Compression	monovalent	Air/Water	Germany	15	e.	22.5	3	'/.	140	15	1150	35
14	Gas Compression	bivalent Oil Backup	Air/Water	Germany	15	e.	22.5	3	15	HP 150 BU 68	15	1070	32

e. = existing; → = item is combined with the next item to the right; n.a. = not available

HP = Heat Pump; BU = Backup

* Partial system costs included only (see notes)

Notes to Table 6.1:

No. 1 Electric Compression Heat Pump
Monovalent
Soil/Water
Belgium
6 kW

(i) The system is designed to provide space and hot water for a single family house in Limelette, French Brabant, Belgium with 84 m² floor area, 225 m³ internal volume and a coefficient of mean thermal transmittance of 0.89 W/m²K. The heat demand specifications are: 2754 degree days per year, 18 °C inside temperature.
The heat pump, which has an output peak capacity of 5.5 kW, provides space heat only, while a conventional electric resistance heater of 0.5 kW capacity, which is loaded during off-peak times, provides 120 l/day hot water.

(ii) The heat pump is combined with a hot water storage system of 1 m³, which allows off-peak loading.

(iii) Design temperature outside the house is -7 °C.

(iv) Electricity consumption for water pump, compressor and auxiliary systems is 7000 kWh/yr. 83 % of the electricity input occurs off-peak.

(v) Capital costs:

Heat pump	6500 $
Radiators (floor heating system)	3400 $
Hot water boiler	1000 $
Heat storage	1900 $
Auxiliary systems (controls etc.)	1700 $
Total	14500 $

- Assessor: Stephane Hecq, Voie du Roman Pays, 34, B-1348 Louvain-La-Neuve, Belgium

Notes to Table 6.1:

No. 2 Electric Compression Heat Pump
Bivalent, Electric Backup
Air/Air
Belgium
6 kW

(i) See No. 1 (i) for the specification of the house and the demand.

(ii) The heat source for the heat pump is a mix of fresh and recycled warm air. Backup is provided by an auxiliary resistance heater; the annual backup fraction is not specified.

(iii) Design temperature outside the house is -7 °C.

(iv) Electricity consumption for air vents, compressor and auxiliary systems is 9300 kWh/yr with 40 % consumed during the day, 27 % at off-peak hours and 33 % at other intervals.

(v) Capital costs:

Heat pump	3400 $
Air convectors	2400 $
Hot water boiler	700 $
Total	6500 $

- Assessor: Stephane Hecq, Voie du Roman Pays, 34,
B-1348 Louvain-La-Neuve, Belgium

Notes to Table 6.1:

No. 3 Electric Compression Heat Pump
Bivalent, Electric Backup
Air/Water
Denmark
6 kW

(i) The heat pump is designed to provide space heat and hot water for a new designed single-family house in Denmark with 120 m^2 floor area, 300 m^3 internal volume and a coefficient of mean thermal transmittance of 0.33 W/m^2 K. The heat demand specifications are: 2258 degree days per year, 20 °C inside temperature.

(ii) The heat pump is combined with a small hot water storage tank of 200 l and an electric resistance water heating system as backup. The annual backup fraction is 10 %.

(iii) Design outside temperature is -12 °C.

(iv) Electricity consumption:

Heat pump and auxiliary systems	7000 kWh/yr
Backup	1700 kWh/yr

(v) Coefficient of performance: $1.8 \leq COP \leq 2.5$

(vi) Capital costs:

Heat pump, excluding compressor	2700 - 3800 $
Compressor	500 - 600 $
Storage tank and electric heater	1000 - 1200 $
Radiator system	2000 - 2500 $
Plumbing, electric equipment	900 - 1200 $
Outdoor installations	100 - 0 $
Total	7200 - 9300 $

- Assessors: Lars Henrik Nielsen/C.J. Christensen, Riso, Denmark

Notes to Table 6.1:

No. 4 Electric Compression Heat Pump
Monovalent
Soil/Water
Denmark
6 kW

(i) See No. 3 (i) for specification of the house and the demand.

(ii) Design outside temperature is -12 °C.

(iii) Electricity consumption is 7500 kWh/yr.

(iv) Coefficient of performance: $1.8 \leq COP \leq 2.5$

(v) Capital costs:

Heat pump, excluding compressor	3000 - 3600 $
Compressor	1400 - 1800 $
Radiator system	2000 - 2500 $
Plumbing, electric equipment	1400 - 1800 $
Heat exchanger and earth works	1800 - 2700 $
Investment costs for the h.p. room	900 - 1300 $
Total	10500 -13700 $

- Assessors: Lars Henrik Nielsen, Riso, Denmark

No. 5 Gas Absorption Heat Pump
Monovalent
Air/Water
United Kingdom
8 kW

Notes to Table 6.1:

(i) The heat pump is designed to provide space heat for a single-family house in the United Kingdom with 90 m^2 floor area, 225 m^3 internal volume and a coefficient of mean thermal transmittance of 1.1 W/m^2 K. The heat demand specifications are: 2200 degree days per year, 20 °C inside temperature.

(ii) First commercial service year is between 1985 and 1986.

(iii) Costs are in the range of $ 5000 to $ 7000. They include cost components for the heat pump, associated installations and controls only. Cost fractions of the heat distribution system are not included.

- Assessor: A.V. Ward, ETSU, Harwell, England

No. 6 Electric Compression Heat Pump
Bivalent, Electric Backup
Air/Water
Denmark
9 kW

(i) The heat pump is designed to provide space heat and hot water for an older single-family house in Denmark with 120 m^2 floor area, 300 m^3 internal volume and a coefficient of mean thermal transmittance of 0.57 W/m^2 K. The heat demand specifications are: 2978 degree days per year, 20 °C inside temperature.

(ii) The heat pump is combined with a small hot water storage tank of 200 l and an electric resistance water heating system as backup. The annual backup fraction is 10 %.

(iii) Design outside temperature is -12 °C.

Notes to Table 6.1:

(iv) Electricity consumption:

Heat pump and auxiliary systems	10700 kWh/yr
Backup	2600 kWh/yr

(v) Coefficient of performance: $1.8 \leq COP \leq 2.5$

(vi) Capital costs:

Heat pump, excluding compressor	3200 - 4300 $
Compressor	800 - 1000 $
Storage tank and electric heater	1000 - 1200 $
Radiator system	2700 - 3400 $
Plumbing, electric equipment	1200 - 1600 $
Outdoor installations	100 - 0 $
Total	9000 - 11500 $

- Assessors: Lars Henrik Nielsen/C.J. Christensen, Riso, Denmark

No. 7 Electric Compression Heat Pump
Monovalent
Soil/Water
Denmark
9 kW

(i) See No. 6 (i) for the specification of the house and the demand.

(ii) Design outside temperature is -12 °C.

(iii) Electricity consumption is 12000 kWh/yr.

(iv) Coefficient of performance: $1.8 \leq COP \leq 2.5$

Notes to Table 6.1:

(v) Capital costs:

Heat pump, excluding compressor	3200 - 3400 $
Compressor	2100 - 2700 $
Radiator system	2700 - 3400 $
Plumbing, electric equipment	1400 - 1800 $
Heat exchanger and earth works	2300 - 3600 $
Investment costs for the h.p. room	900 - 1300 $
Total	12600 - 16200 $

- Assessors: Lars Henrik Nielsen, Riso, Denmark

No. 8 Electric Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Switzerland
10.6 kW

(i) The heat pump is designed to provide space heat for a single-family house at Berne in Switzerland with 162 m^2 floor area, 474 m^3 internal volume and a coefficient of mean thermal transmittance of 0.62 W/m^2 K. The heat demand specifications are: 3870 degree days per year, 20 °C inside temperature.

(ii) The heat pump is combined with an oil backup system which provides 50 % of the annual heat supply. The efficiency of the backup system is 80 %.

(iii) Design outside temperature: -11 °C

(iv) Electricity consumption for the heat pump and auxiliary systems is 13000 kWh/yr.

(v) Capital cost estimated at $ 19 500. No cost breakdown available.

- Assessor: J. Wochele, Eidgenössisches Institut für Reaktorforschung, Würenlingen, Switzerland.

Notes to Table 6.1:

No. 9 Electric Compression Heat Pump
Monovalent
Soil/Water
Switzerland
10.6 kW

(i) See No. 8 (i) for the specification of the house and the demand.

(ii) Design outside temperature is -11 °C.

(iii) Electricity consumption for the heat pump and auxiliary systems is 5000 kWh/yr.

(iv) Capital cost estimated at $ 19 500. No cost breakdown available.

- Assessor: J. Wochele, Eidgenössisches Institut für Reaktorforschung, Würenlingen, Switzerland.

No. 10 Electric Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Germany
15 kW

(i) The heat pump is designed to provide space heat and hot water for a single-family house in Germany with 130 m^2 floor area, 390 m^3 internal volume and a coefficient of mean thermal transmittance of 0.85 W/m^2 K. The heat demand specifications are: 3000 degree days per year, 20 °C inside temperature.

Notes to Table 6.1:

(ii) The heat pump is combined with a conventional oil burner, which provides 30 % of the annual heat supply. The heat pump operates under "alternative mode" conditions. The switching point is +3 °C outside temperature: above this temperature the heat pump works only, below it the oil burner takes over heat production. Peak output capacity is 7.5 kW at +3 °C for the heat pump, and is 15 kW at -15 °C for the oil burner.

(iii) Air throughput: 4500 m^3/h.

(iv) Electric capacity:

Compressor motor	3 kW
Air vents	0.3 kW

Annual electricity consumption:

Compressor and air vents	4000 kWh
Auxiliary systems	500 kWh

(v) Radiator temperatures (feedwater/backflow):

Heat pump	60/50 °C
Oil burner	90/70 °C

(vi) The coefficient of performance is 2.3 at an outside temperature of +3 °C. The annual average COP is 3.6, excluding the heat distribution system (distribution efficiency η_D : 0.82).

Notes to Table 6.1:

(vii) Capital costs:

Heat pump	4500 $
Air ducts	800 $
Connection & mounting of h.p.	700 $
Boiler	900 $
Oil burner	600 $
Oil tank	300 $
Piping system	1200 $
Radiators	1000 $
Controls	900 $
Space requirements, chimney	2300 $
Total system	13200 $

- Assessor: Dethlef Orth, KFA Jülich

No. 11 Electric Compression Heat Pump
Monovalent
Water/Water
Germany
15 kW

(i) See No. 10 (i) for the specification of the house and the demand.

(ii) The heat pump uses 3 m^3/h of underground water at +8 °C (average temperature) as the heat source.

(iii) Design outside temperature is -15 °C.

(iv) Electric capacity:

Compressor motor	6 kW
Underground water pump	0.7 kW

Electricity consumption is 11500 kWh/yr.

Notes to Table 6.1:

(v) Radiator temperatures (feedwater/backflow) are 60/50 °C.

(vi) The coefficient of performance of the heat pump alone is 2.6 at +8 °C underground water temperature and -15 °C air temperature. The annual average COP of the total system, excluding the heat distribution system is 3.9 (η_D = 0.85).

(vii) Capital costs:

Heat pump	5400 $
Heat source preparation	3000 $
Connection & mounting of h.p.	600 $
Piping system	1200 $
Radiators	2000 $
Controls	600 $
Space requirements	1400 $
Total	14200 $

- Assessor: Dethlef Orth, KFA Jülich

No. 12 Gas Compression Heat Pump
Monovalent
Water/Water
Germany
15 kW

(i) See No. 10 (i) for the specification of the house and the demand.

(ii) The heat pump uses 2 m³/h of underground water at +8 °C (average temperature) as the heat source.

(iii) Design outside temperature is -15 °C.

Notes to Table 6.1:

(iv) Nominal power of heat pump sub-systems

Gas engine	3.2 kW
Ground water pump	0.7 kW

Thermal power of the gas engine exhaust: 9.1 kW
(measured at -15 °C outside air temperature)
Electricity consumption for auxiliary systems:
1400 kWh/yr

(v) Radiator temperatures (feedwater/backflow) are 60/50 °C.

(vi) The annual average COP for heat generation is 1.8 excluding heat distribution (η_D = 0.86)

(vi) Capital cost:

Heat pump	6000 $
Gas engine	1800 $
Underground source	3000 $
Gas connection to the house	900 $
Mounting	600 $
Piping system	1200 $
Radiator system	2000 $
Controls	600 $
Space requirements, chimney	2300 $
Total	18400 $

- Assessor: Dethlef Orth, KFA Jülich

No. 13 Diesel Compression Heat Pump
Monovalent
Air/Water
Germany
15 kW

(i) See No. 10 (i) for the specification of the house and the demand.

(ii) Design outside temperature is -15 °C.

Notes to Table 6.1:

(iii) Nominal power of heat pump sub-systems:

Diesel motor	3.9 kW
Air vent	0.3 kW

Thermal power of the diesel engine exhaust (measured at -15 °C outside air temperature: 8.0 kW
Electricity consumption for auxiliary systems: 1400 kWh/yr.

(iv) Radiator temperatures (feedwater/backflow) are 60/50 °C.

(v) The annual COP for the heat generation averages to 1.65 (excluding heat distribution: $\eta_D = 0.85$).

(v) Capital Cost:

Heat Pump	7700 $
Diesel motor	2100 $
Diesel tank system	400 $
Mounting	600 $
Piping system	1200 $
Radiator system	2000 $
Controls	600 $
Space requirements, chimney	2600 $
Total	17200 $

- Assessor: Dethlef Orth, KFA Jülich

No. 14 Gas Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Germany
15 kW

(i) See No. 10 (i) for the specification of the house and the demand.

Notes to Table 6.1:

(ii) The heat pump, which is powered by a gas-fired I/C engine, is combined with a conventional oil burner which provides 15 % of the annual heat supply. The heat pump is designed for "parallel mode" operation in order to reduce the use of pipeline gas at peaking hours. The switching point is +3 °C: above this temperature the heat pump works only, below it the heat pump and oil burner contribute to supply the heat load. Peak output capacity is 7.5 kW at +3 °C outside temperature for the heat pump and is 15 kW at -15 °C outside temperature for the combined heat pump/oil burner.

(iii)

Gas motor	1.7 kW
Air vents	0.2 kW
Gas motor exhaust heat	3.5 kW

(iv) Radiator temperatures (feedwater/backflow) are 60/50 °C.

(v) The annual COP of the heat pump averages to 1.75. The efficiency of the oil backup system is 0.8. Heat distribution efficiency (η_D = 0.85) is excluded.

(vi) Capital costs:

Heat pump	5100 $
Gas engine	1200 $
Gas connection to the house	900 $
Mounting	600 $
Boiler	900 $
Oil burner	600 $
Oil tank system	300 $
Piping system	1200 $
Radiator system	2000 $
Controls	900 $
Space requirements, chimney	2300 $
Total	16000 $

- Assessor: Dethlef Orth, KFA Jülich

TABLE 6.2 - Heat Pumps for Two-Family Houses

NO.	SYSTEM	OPERATIONAL MODE	HEAT SOURCE HEAT DISTRIBUTION	LOCATION	DESIGN CAPACITY kW	FIRST COMMERCIAL SERVICE YEAR -	ANNUAL SPACE HEATING DEMAND 10^3kWh	ANNUAL WATER HEATING DEMAND 10^3 kWh	BACKUP FRACTION %	ANNUAL OVERALL EFFICIENCY %	ECONOMIC LIFETIME Yrs	TOTAL CAPITAL COST $/kW	TOTAL FIXED O&M COST $/kW
1	Electric Compression	bivalent Oil Backup	Air/Water	Germany	20	e.	30	4	30	HP 300 Bu 72	20	797	23
2	Electric Compression	monovalent	Water/Water	Germany	20	e.	30	4	-	330	20	805	24
3	Gas Compression	monovalent	Water/Water	Germany	20	e.	30	4	-	150	15	979	29
4	Diesel Compression	monovalent	Air/Water	Germany	20	e.	30	4	-	140	15	937	28
5	Gas Compression	bivalent Oil Backup	Air/Water	Germany	20	e.	30	4	15	HP 150 Bu 68	15	909	27

e. = existing HP = Heat Pump Bu = Backup System

Notes to Table 6.2:

No. 1 Electric Compression Heat Pumps
Bivalent, Oil Backup
Air/Water
Germany
20 kW

(i) The heat pump system is designed to provide space heat and hot water for a two-family house in Germany with 200 m² floor area, 686 m² internal volume and a coefficient of mean thermal transmittance of 0.87 W/m² K. The heat demand specifications are: 3000 degree days per year, 20 °C inside temperature.

(ii) The heat pump is combined with a conventional oil burner which provides 30 % of the annual heat supply. The heat pump operates under "alternate mode" conditions. The switching point is at +3 °C outside air temperature: above this temperature the heat pump operates, below it the oil burner takes over heat production. Peak output power is 10 kW at + 3 °C outside temperature for the heat pump, 20 kW at - 15 °C outside temperature for the oil burner.

(iii) Air throughput: 6000 m³/h

(iv) Electric power

Compressor motor	4	kW
Air vents	0.4	kW

Annual electricity consumption:

Compressor and air vents:	5236	kWh
Auxiliary systems:	550	kWh

Notes to Table 6.2

(v) Radiator temperatures (feedwater/backflow):

Heat pump	60/50 °C
Oil Backup	90/70 °C

(vi) The coefficient of performance of the heat pump is 2.3 at +3 °C outside temperature. Over the year the COP averages to 3.6. These figures do not include the efficiency of the heat distribution and regulation (η_D = 0.85)

(vii) Capital costs:

Heat pump	5 880 $
Air ducts	840 $
Connection and mounting of H.P	780 $
Boiler	950 $
Oil burner	640 $
Oil tank	420 $
Piping system	1 400 $
Radiators	1 440 $
Controls	940 $
Constructional extra cost	2 640 $
Total system	15 930 $

- Assessor: Dethlef Orth, KFA Jülich

No. 2: Electric Compression Heat Pump
Monovalent
Water/Water
Germany
20 kW

Notes to Table 6.2

(i) See No. 1 (i) for the specification of the house and the demand.

(ii) The heat pump uses 4 m^3/h of ground water at +8 ° C (average temperature) as the heat source.

(iii) Design outside temperature is -15 °C.

(iv) Electric power:

Compressor motor	8	kW
Ground water pump	0.7	kW

Electricity consumption is 14 790 kWh/yr.

(v) Radiator temperatures (feedwater/backflow): 60/50 °C

(vi) The coefficient of performance (COP) of the heat pump compressor is 2.6 at +8 °C ground water temperature and -15 °C outside air temperature. The annual average COP of the total system, excluding heat distribution, is 3.9 (η_D= 0.85).

(vii) Capital Costs:

Heat pump	6 780 $
Heat source preparation	3 000 $
Connection & mounting of H.P.	720 $
Piping system	1 400 $
Radiators	2 100 $
Controls	660 $
Constructional extra cost	1 440 $
Total system	16 100 $

- Assessor: Dethlef Orth, KFA Jülich

Notes to Table 6.2

No. 3 Gas Compression Heat Pump
Monovalent
Water/Water
Germany
20 kW

(i) See No. 1 (i) for the specification of the house and the demand.

(ii) The heat pump uses 2.5 m^3/h of ground water at +8 °C average temperature as heat source.

(iii) Design outside temperature is -15 °C.

(iv) Nominal power of heat pump sub-systems

Gas engine	4.3	kW
Ground water pump	0.7	kW

Thermal power of the gas engine exhaust 12.2 kW (measured at -15 °C outside air temperature).

Electricity consumption for auxiliary systems: 1 500 kWh/yr.

(v) Radiator temperatures (feedwater/backflow): 60/50 °C

(vi) The coefficient of performance (COP) of the compressor cycle (measured at -15 °C outside air temperature) is 2. The annual/average overall COP for the heat generation, excluding heat distribution is 1.8 (η_D = 0.85).

Notes to Table 6.2

(vii) Capital Costs:

Heat pump	6 420 $
Gas engine	2 100 $
Ground water well	3 000 $
Connection to gas grid	960 $
Mounting	720 $
Piping system	1 400 $
Radiators	2 100 $
Controls	600 $
Constructional extra cost	2 280 $
Total System	19 580 $

- Assessor: Dethlef Orth, KFA Jülich

No. 4 Diesel Compression Heat Pump
Monovalent
Air/Water
Germany
20 kW

(i) See No. 1 (i) for the specification of the house and demand.

(ii) Design temperature of the heat pump system is -15 °C.

(iii) Nominal power of heat pump sub-systems:

Diesel engine	5.3 kW
Air vents	0.4 kW

Notes to Table 6.2

Thermal power of the diesel engine exhaust (measured at -15 °C outside air temperature) is 10.7 kW. Electricity consumption for auxiliary systems is 1 800 kWh/yr.

(iv) Radiator temperatures (feedwater/backflow): 60/50 °C

(v) The annual average overall COP for the heat generation, excluding heat distribution, is 1.65 (distribution efficiency: 0.85).

(vi) Capital Costs:

Heat Pump	8 100 $
Diesel engine	2 520 $
Diesel tank system	420 $
Mounting	600 $
Piping system	1 400 $
Radiators	2 100 $
Controls	600 $
Constructional extra cost	3 000 $
Total system	18 740 $

- Assessor: Dethlef Orth, KFA Jülich

No. 5: Gas Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Germany
20 kW

Notes to Table 6.2

(i) See No. 1 for specifications of the house and the demand.

(ii) The heat pump is combined with a conventional oil burner which provides 15 % of the annual heat supply. The heat pump is designed for "parallel mode" operation in order to reduce the use of pipeline gas at peaking hours.

The switching point is at 3 °C outside air temperature: above this temperature only the heat pump operates, below it heat pump and oil burner contribute to supply.
Output power of the heat pump at +3 °C outside air temperature is 10 kW.

(iii) Nominal power of heat pump sub-systems:

Gas engine	2.3 kW
Air vents	0.3 kW

Thermal power of the gas heat pump exhaust (measured at +3 °C outside temperature) 4.7 kW.

(iv) Radiator temperatures (feedwater/backflow): 60/50 °C.

(v) The annual COP of the heat pump averages to 1.75. The efficiency of the oil backup system is 0.8. Heat distribution efficiency is excluded (η_D = 0.85).

Notes to Table 6.2

(vi) Capital costs:

Heat pump	5 520 $
Gas engine	1 500 $
Connection to gas grid	900 $
Mounting	600 $
Boiler	960 $
Oil burner	640 $
Oil tank	300 $
Piping system	1 400 $
Radiators	2 100 $
Controls	900 $
Constructional extra cost	3 360 $
Total system	18 180 $

- Assessor: Dethlef Orth, KFA Jülich

TABLE 6.3 - Heat Pumps to Multi-Family Houses

NO.	SYSTEM	OPERATIONAL MODE	HEAT SOURCE HEAT DISTRIBUTION	LOCATION	DESIGN CAPACITY kW	FIRST COMMERCIAL SERVICE YEAR -	ANNUAL SPACE HEATING DEMAND 10^3kWh	ANNUAL WATER HEATING DEMAND 10^3 kWh	BACKUP FRACTION %	ANNUAL OVERALL EFFICIENCY %	ECONOMIC LIFETIME Yrs	TOTAL CAPITAL COST $/kW	TOTAL FIXED O&M COST $/kW
1	Electric Compression	bivalent, Oil Backup	Air/Water	Germany	78	e.	120,9	19,5	30	HP_{300} Bu_{72}	20	466	14
2	Electric Compression	monovalent	Water/Water	Germany	78	e.	120,9	19,5	-	330	20	538	16
3	Gas Compression	monovalent	Water/Water	Germany	78	e.	120,9	19,5	-	150	15	528	16
4	Diesel Compression	monovalent	Air/Water	Germany	78	e.	120,9	19,5	-	140	15	635	19
5	Gas Compression	bivalent Oil Backup	Air/Water	Germany	78	e.	120,9	19,5	15	HP_{150} Bu_{68}	15	430	13
6	Electric Compression	monovalent	Water/Water	Switzer-land	40,5	e.	57,2	-	-	300	20	1024	26
7	Electric Compression	bivalent Oil Backup	Air/Water	Switzer-land	40,5	e.	57,2	-	50	HP_{250} Bu_{80}	20	1252	31

e. = existing HP = Heat Pump Bu = Backup System

Notes to Table 6.3

No. 1 Electric Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Germany
78 kW

(i) The heat pump system is designed to provide space heat and hot water for a 12-family house in Germany with 900 m² floor area, 3120 m³ internal volume and a coefficient of mean thermal transmittance of 1.13 W/m² K. The heat demand specifications are 3000 degree days per year, 20 °C inside temperature.

(ii) The heat pump is combined with a conventional oil burner which provides 30 % of the annual heat supply. The heat pump operates under "alternate mode" conditions. The switching point is at +3 °C outside air temperature: above this this temperature the heat pump operates, below it the oil burner provides for the required heating on its own. Peak output power is 39 kW at +9 °C outside temperature for the heat pump, 78 kW at -15 °C for the oil backup system.

(iii) Air throughput: 23 000 m³/h

(iv) Electric power:

Compressor motor:	16 kW
Air vents:	1 kW

Annual electricity consumption:

Compressor and air vents:	18 445 kWh
Auxiliary systems:	700 kWh

Notes to Table 6.3

(v) Radiator temperature: (feedwater/backflow):

Heat Pump 60/50 °C

Oil Backup 90/70 °C

(vi) The coefficient of performance of the heat pump is 2.3 at +3 °C outside temperature. Over the year the COP averages to 3.6. These figures do not include the efficiency of heat distribution and regulation ($\eta_D = 0.85$).

(vii) Capital costs:

Heat pump	13 800 $
Air ducts	1 680 $
Connection and mounting of H.P.	1 920 $
Boiler	1 560 $
Oil burner	640 $
Oil tank	660 $
Piping system	3 530 $
Radiators	6 190 $
Controls	990 $
Constructional extra cost	5 400 $
Total system	36 370 $

- Assessor: Dethlef Orth, KFA Jülich

No. 2: Electric Compression Heat Pump
Monovalent
Water/Water
Germany
78 kW

(i) See No. 1 (i) for the specification of the house and the demand.

Notes to Table 6.3

(ii) The heat pump uses 15 m³/h of ground water at +8 °C average temperature as heat source.

(iii) Design outside temperature is -15 °C.

(iv) Electric power

Compressor motor	30 kW
Ground water pump	1.5 kW

The annual electricity consumption is 53 550 kWh.

(v) Radiator temperatures (feedwater/backflow): 60/50 °C.

(vi) The coefficient of performance (COP) of the heat pump alone is 2.6 at +8 °C ground water temperature and -15 °C air temperature. The annual average COP of the total system, excluding heat distribution is 3.9 (η_D = 0.85).

(vii) Capital costs:

Heat pump	20 400 $
Heat source preparation	4 800 $
Connection and mounting of H.P.	1 320 $
Piping system	3 530 $
Radiators	9 070 $
Controls	720 $
Constructional extra cost	2 160 $
Total system	42 000 $

- Assessor: Dethlef Orth, KFA Jülich

Notes to Table 6.3

No. 3: Gas Compression Heat Pump
Monovalent
Water/Water
Germany
78 kW

(i) See No. 1 (i) for the specification of the house and the demand.

(ii) The heat pump uses 7 m^3/h of ground water at +8 °C average temperature as heat source.

(iii) Design temperature of the heat pump system is -15 °C.

(iv) Nominal power of heat pump sub-systems:

Gas engine	18	kW
Ground water pump	1.5	kW

Thermal power of the gas engine exhaust (measured at -15 °C outside air temperature): 42 kW.

Electricity consumption for auxiliary systems
2 700 kWh/yr.

(v) Radiator temperatures (feedwater/backflow): 60/50 °C.

(vi) The annual average overall COP for the heat generation, excluding heat distribution, is 1.8 (η_D =0.85).

Notes to Table 6.3

(vii) Capital Costs:

Compressor cycle	15 000 $
Gas motor	3 000 $
Ground water well	4 200 $
Connection to gas grid	1 200 $
Mounting	900 $
Piping system	3 530 $
Radiators	9 070 $
Controls	720 $
Constructional extra cost	3 600 $
Total system	41 220 $

- Assessor: Dethlef Orth, KFA Jülich

No. 4: Diesel Compression Heat Pump
Monovalent
Air/Water
Germany
78 kW

(i) See No. 1 (i) for the specification of the house and the demand.

(ii) Design outside temperature is -15 °C.

(iii) Nominal power of heat pump sub-systems

Diesel engine	15.5 kW
Air vents	1.0 kW

Thermal power of the diesel engine exhaust (measured at -15 °C outside air temperature) 41 kW

Electricity consumption for auxiliary systems:
5 900 kWh/yr.

Notes to Table 6.3

(iv) Radiator temperatures (feedwater/backflow): 60/50 °C

(v) The coefficient of performance (COP) of the compressor cycle (measured at -15 °C outside air temperature) is 1.8. The annual average overall COP for the heat generation, excluding heat distribution, is 1.65 (η_D = 0.85).

(vi) Capital costs:

Heat pump	23 400 $
Diesel engine	4 620 $
Diesel tank system	1 560 $
Mounting	1 200 $
Piping system	3 530 $
Radiators	9 070 $
Controls	720 $
Constructional extra cost	5 400 $
Total system	49 500 $

- Assessor: Dethlef Orth, KFA Jülich

No. 5: Gas Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Germany
78 kW

(i) See No. 1 for specification of the house and the demand.

(ii) The heat pump is combined with a conventional oil burner which provides 15 % of the annual heat supply. The heat pump is designed for "parallel mode" operation in order to reduce the use of pipeline gas at peaking hours.

Notes to Table 6.3

The switching point is at +3 °C outside air temperature: above this temperature only the heat pump operates, below it both the heat pump and the oil burner contribute to supply. Output power of the heat pump at +3 °C outside air temperature is 39 kW, and is 78 kW at -15 °C outside temperature for the heat pump/oil burner combination.

(iii) Nominal power of heat pump sub-system

Gas engine	5 kW
Air vents	0.7 kW

Thermal power of the gas heat pump exhaust (measured at +3 °C outside temperature): 18.3 kW

(iv) Radiator temperature (feedwater/backflow): 60/50 °C.

(v) The annual COP of the heat pump averages to 1.75. The efficiency of the oil backup system is 0.8. Heat distribution efficiency (η_D = 0.85) is excluded.

(vi) Capital costs:

Heat pump	8 400 $
Gas engine	2 400 $
Connection to gas grid	900 $
Mounting	900 $
Boiler	1 560 $
Oil burner	640 $
Oil tank	660 $
Piping system	3 530 $
Radiators	9 070 $
Controls	900 $
Constructional extra cost	4 500 $
Total system	33 550 $

- Assessor: Dethlef Orth, KFA Jülich

Notes to Table 6.3

No. 6: Electric Compression Heat Pump
Monovalent
Water/Water
Switzerland
40.5 kW

(i) The heat pump is designed to provide space heat for an 8-family house at Bern in Switzerland with 517 m^2 floor area, 2210 m^3 internal volume and a coefficient of mean thermal transmittance of 0.74 W/m^2 K. The heat demand specifications are: 3 870 degree days per year. 20 °C inside temperature.

(ii) Design temperature of the heat pump system is -11 °C.

(iii) Electricity consumption of the heat pump and the auxiliary systems is 19 000 kWh/yr.

(iv) Radiator temperatures (feedwater/backflow): 55/45 °C.

(v) Capital cost estimated to be $ 41 500.
No cost breakdown available.

- Assessor: J. Wochele, Eidgenössisches Institut für Reaktorforschung, Würenlingen, Switzerland.

No. 7: Electric Compression Heat Pump
Bivalent, Oil Backup
Air/Water
Switzerland
40.5 kW

(i) See No. 5 (i) for the specification of the house and the demand.

(ii) The heat pump is combined with an oil backup system which provides 50 % of the annual heat supply.

Notes to Table 6.3

(iii) Design outside temperature is -11 °C.

(iv) Electricity consumption of the heat pump and auxiliary systems is 11 400 kWh/yr.

(v) Radiator temperatures (feedwater/backflow): 55/45 °C.

(vi) Capital cost estimated to be $ 50 700.
No cost breakdown available.

- Assessor: J. Wochele, Eidgenössisches Institut für Reaktorforschung, Würenlingen, Switzerland

6.3 References

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/6.2/ "Draft Final Report of the Heat Pump Technology
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7. TRANSPORT TECHNOLOGIES

7.1 Cars

In 1980 the world, excluding the Soviet Union, Eastern Europe and China, consumed 634 million tonnes of gasoline, representing 27 % of a total consumption of 2375 million tonnes of oil products (Ref. 7.1). Aside from the comparatively small volumes used by boats and light aircraft, this gasoline was used almost entirely by cars, trucks and other road vehicles. Some 404 million motor vehicles were on register in the world in 1980 (Ref. 7.2) of which 315 million were cars, the largest fraction of which were fuelled by gasoline with most of the remainder running on diesel. In addition, 89 million trucks and buses were predominantly fuelled by diesel with a small fraction running on gasoline. Therefore, the potential for oil savings by either transport fuel substitution or increased efficiency of use by vehicles is enormous.

A number of alternative transport energy forms are already making inroads into the road vehicle markets traditionally held by gasoline and automotive diesel oil, or are potentially capable of doing so. These fuels are

- liquefied petroleum gas (LPG) - i.e. propane and butane produced by oil refineries or co-produced with crude oil and natural gas from sedimentary deposits,
- the alcohols, methanol and ethanol, which are produced from coal, natural gas or biomass, and which can be used in pure form or in blends with gasoline and diesel oil,
- vegetable oils from seeds, and hydrocarbons in latex form from various plants such as those from the Euphorbia and Asclepias families,
- compressed natural gas (CNG),
- hydrogen gas, and
- stored electricity.

The opportunities for increasing fuel economy in cars are considerable and significant progress has already been made since the 1973/74 leap in oil prices. In 1974 the average car sold in the U.S.A. achieved a fuel consumption of 18 litres/100 km (equivalent to a fuel economy of 13 miles per U.S. gallon). By 1980 the consumption had fallen to an estimated 12.4 litres/100 km (19 m.p.g). By mandate of Congress the fleet of automobiles built for the 1985 model year must achieve an average of 8.5 litres/100 km (27.5 m.p.g.), as measured by dynamometer tests administered by the Environmental Protection Agency (Ref. 7.3).

Such reductions in fuel consumption have been mainly achieved by decreasing vehicle mass and engine size and by increasing engine efficiency.

Vehicle mass is an extremely important factor - the 18 litres/100 km consumption value might be associated with a 6 litre V8 powered 1850 kg car (Ref. 7.4), while the 12.5 litres/100 km consumption is characteristic of a 4 cylinder, 2 litre car with a mass of 1300 kg.

Ref. 7.5 proposes a formula to calculate the fuel consumption (F) of various vehicles of different mass (M) containing 4, 6 and 8 cylinder engines of capacities (C) of 1 to 6 litres. The formula is

$$F \text{ (litres/100 km)} = 4.4 + 0.0061\ M \text{ (kg)} + 0.75\ C \text{ (litres)} + An$$

$$\begin{aligned} \text{where } An &= -1.4 \quad \text{for } n = 4 \text{ cylinders} \\ &= -0.9 \quad \text{for } n = 6 \\ \text{and} \quad &= 0.25 \quad \text{for } n = 8 \end{aligned}$$

Reference 7.3 gives a specific example of how mass and engine size can be reduced by good design without dramatic loss in the utility of useful interior space. One of the new Chrysler 'K cars', the five-passenger 1981 Plymouth Reliant has an

unloaded 'curb' mass of 1040 kg and, with the addition of an average load for U.S. urban driving of 140 kg, has a 'test' mass of 1180 kg. The curb mass is 485 kg (30 percent) less than the 1980 Plymouth Volaré with a sacrifice of only 4 percent in the volume of the passenger compartment and 6 percent in the trunk space. As a result of this mass reduction the engin power has been reduced from 89 kW to 63 kW with a corresponding fall in consumption from 14 litres/100 km to 9.8 litres/100 km. An important design change in Reliant was the changeover to front-wheel drive with the engine mounted transversely (a common European feature). This permits a shortened engine compartment and eliminates the long heavy drive shaft and the associated tunnel through the passenger compartment.

Reference 7.3 comments that further major reductions in weight could be gained by replacing steel with aluminium, fiber-reinforced plastics and foam-filled structures permitting ultimate weights 40 percent less than those persently being achieved.

In stop-and-go driving under 30 km/hr, it is vehicle mass and the overcoming of rolling resistance that primarily determines fuel consumption, but at speeds above that, air resistance becomes important. For every doubling of the speed, aerodynamic drag increases fourfold and the engine power required to cope with it is eight times as great. At 90 km/hr highway cruising, a conventional medium-sized sedan uses roughly 65 percent of its engine power to overcome air resistance. In this regard, important parameters of a vehicle are frontal area (typically 2 square metres for a modern medium sized car) and the aerodynamic drag coefficient which is a relative measure of the air resistance of a body. A flat square plate has a coefficient of drag (CD) of 1.17. The average late-model car has a CD of about 0.45 but modern design has achieved CDs of 0.31 - 0.35 (Ref. 7.6).

Reduction of tyre rolling resistance by switching from cross-ply to steel-cased radial-ply tyres can also give significant fuel savings (approx. 5 %).

There are opportunities for increasing the overall efficiency of road vehicles by means of technical improvements to the transmission that delivers power to the wheels. In present day cars, the gearing of transmissions usually provides for the selection of only two to four specific rotational speeds of the engine for a given road speed. As a result, in acceleration from zero to 80 km/hr with a manual transmission, the average engine power output is usually limited to about 80 percent of the peak output (Ref. 7.3).

An ability to harness the engine's peak power at all road speeds would be provided by a continuously variable transmission (CVT). CVT systems are under intensive development but as yet, are not sufficiently cheap, reliable and efficient for commercialisation. If they become commercially available it is likely they will be under microprocessor control in the vehicle allowing the automatic selection of the most efficient engine speed with a given power output.

The issues of vehicle mass, aerodynamic drag and drive transmission raised above are common to all cars irrespective of engine type and fuel used (although the consumption values quoted above as examples, were for the familiar gasoline fuelled otto cycle engine). In parallel to developments in these areas of vehicle design, considerable effort is going into improving the fuel economy of spark ignition (otto) and diesel engines themselves, consistent with tighter emissions requirements. A brief overview of these developments is given in Section 7.1.1.

As well, existing types of engines are being modified to handle other liquid and gaseous fuels. Section 7.1.2 discusses the possibilities for using alcohol fuels and Section 7.1.3 treats CNG and LPG. Section 7.1.4 briefly considers the electric battery vehicle and Section 7.1.5 summarizes key economic and technical data provided by Australian and Italian assessors for automobile technologies.

7.1.1 Otto and Diesel Engines

All engines must complete a cycle of events which typically proceed in order of induction, compression, heat addition, expansion and heat rejection. In the conventional otto (spark ignition) engine a uniform air/fuel mixture enters the cylinder as the piston moves down (inductionstroke) and is compressed by the rising piston. Heat is produced at constant volume in the cylinder after the fuel is ignited by the spark-plug. The piston is driven downwards doing work in the expansion (power) stroke. In a return stroke of the piston the products of combustion are exausted to the atmosphere where final heat rejection takes place. The ratio of the cylinder volume at maximum expansion to the volume at maximum compression is called the compression ratio. Higher compression ratios mean higher thermal efficiencies, more power relative to weight and better fuel economy. However, if the compression volume is too high the fuel will self ignite (predetonate) resulting in destructive engine 'knock'. The development of higher quality (high octane) gasolines containing increased volumes of knock-resistant hydrocarbons permitted designers to increase compression ratios over the years. However, this trend may not continue as the quality of oil feedstocks will decline with resource depletion. Raising compression ratios also acts to shift energy consumption to the refinery, which needs more crude oil and more capital to make higher-octane fuel, particularly now that tetramethyl and tetraethyl lead are falling out of favour as octane boosters, for various environmental reasons.

In the high speed compression ignition diesel engine air alone is compressed during most of the compression stroke. Fuel injection begins before the end of the compression stroke and before the air is hot enough for fuel ignition. Oil accumulates and after ignition occurs, there is a period of burning at constant volume and rising pressure. A period of further injection occurs during which the cylinder executes an expansion stroke with burning occuring at constant pressure as

in a slow speed diesel. Further expansion occurs after the burning stops, and the exhaust gases are then expelled. If an otto engine and a diesel engine had the same compression ratio the otto engine would be more efficient, but in practice this cannot be achieved because of knock. Predetonation is not a problem in the diesel because only air and not air/fuel is compressed during the compression stroke.

The compression ratio of a typical diesel engine is about in the range of 15 - 20 to one, or more than twice the compression ratio of most spark-ignition engines. The self-igniting diesel engine requires a fuel with easy ignition (high cetane) - i.e. at the opposite end of the scale from slower burning high octane fuels. Unfortunately, cetane rating cannot be altered through molecular manipulation in a refinery as can the octane rating, and so the maximum yield of diesel fuel from a barrel of crude at reasonable cost is fairly fixed. This puts an upper limit on the market penetration of diesel cars given the big demand for diesel by agricultural vehicles, trains, buses and trucks.

There is a distinct difference between a conventional gasoline otto engine and a diesel engine in the air/fuel ratios used. The spark ignition gasoline engine operates with a mixture richer in fuel than the diesel and cannot be operated with a mix much leaner in fuel than stoichiometric (i.e. one where the air/fuel ratio matches the exact molecular proportions required for full chemical reaction). The problem is that too much air prevents ignition. The diesel, on the other hand, cannot operate much richer than stoichiometric.

A major technical improvement to the otto cycle engine that permits its operation with higher air/fuel ratios (lean fuel mixture) is the stratified charge engine. Two major types have been developed (Ref. 7.7). One, the Honda CVCC engine (Ref. 7.8), has been in commercial production since 1974. It has a prechamber and main chamber for each cylinder. A rich air/fuel mixture enters the prechamber at the same time that a very lean

mixture enters the main chamber through a separate intake valve. The spark plug fires the rich mixture, which in turn ignites the lean main mixture. This results in a stable slow burn with low peak temperatures minimising nitrogen oxide formation but with mean temperatures high enough to limit releases of carbon monoxide and hydrocarbons.

In the other type of stratified charge engine, still under development (Ford Proco and Texaco TCCS), fuel and air are directly injected into the cylinder with special intake porting and cylinder head design intended to cause swirling. This results in a rich burn mixture near the flame front originating from a long duration spark. In the Texaco engine, fuel injection occurs late as the piston nears the end of the compression stroke, thereby avoiding predetonation with a resulting greater tolerance for low octane fuels. Because ignition is positive using a spark, there is no demand for a high cetane fuel either.

The Texaco engine shares a desirable feature with the diesel engine: the air is not throttled. Load control is achieved by varying the air/fuel ratio. In the ordinary gasoline engine the controls keep a more or less fixed air/fuel ratio but throttle the overall airflow.

The advanced statified charge engine promises to be at least 30 percent more efficient than current spark ignition engines; meet stringent emission standards; be capable of burning a wide variety of fuels; and, be cost-competitive with standard production engines, although its fuel injection and ignition systems are somewhat more expensive (Ref. 7.7).

Improvements to automotive diesels are likely to come from a switch to direct fuel injection and the use of turbochargers. All current production passenger car diesels use indirect fuel injection designs with some kind of precombustion chamber into which fuel is injected. Fuel economy of the direct injection diesel is about 10 - 15 % better than that of the indirect

version. This is attributable to a faster burn rate, absence of throttling losses between the precombustion chamber and the main chamber, and the elimination of thermal losses associated with the precombustion chamber. Unfortunately, the direct injection diesel is slower, widening the gap further between the specific power output of the diesel and the gasoline engine of equivalent displacement. Emissions are also worse than the indirect injection diesel, which already has severe problems with nitric oxide and particulates output when compared with the gasoline engine.

Turbocharging is standard on large truck diesels and is now being introduced in car engines (for example, in the Peugeot 505). The turbocharger is a combination of a turbine and a compressor. The turbine is spun by the exhaust gases while the compressor, which is on the same shaft, pushes extra air into the cylinder and thereby allows additional fuel to be burned on each power stroke. Turbocharging automotive diesels has made possible fuel-economy advances of between 10 and 15 percent (Ref. 7.3). A Volkswagen Rabbit (Golf) with a test mass of 1090 kg and a turbocharged diesel engine was built in 1976 for the U.S. Department of Transportation. This vehicle achieved a composite drive cycle consumption of diesel fuel of 3.9 litres/100 km. Since the gross calorific value of automotive diesel oil is 38.3 MJ/litre and that of gasoline about 34.7 MJ/litre, this consumption corresponds to about 4.3 litres/100 km for an equivalent gasoline powered car. This result is dramatic evidence of what might be achieved in fuel savings using currently available technology.

7.1.2 Alcohol Fuelled Cars

The alcohols methanol and ethanol can be used in spark ignition engines in either pure form or mixed with gasoline. Table 7.1 details some relevant properties of methanol, ethanol and gasoline.

TABLE 7.1 - Comparative Properties of Methanol, Ethanol and Gasoline

Property	Methanol	Ethanol	Gasoline (Typical)
			regular - premium
Density (g/cm^3)	0.796	0.794	0.72 - 0.76
Research Octane Number	105	110	89-92 and 97-100
Blending Research Octane Number	120-135	120-135	
Calorific Value MJ/L:			
gross	18.06	23.94	32.26 - 35.64
net	15.87	21.62	30.17 - 33.44
Boiling Point at atmospheric pressure (°C)	65	78.5	23-28 to 180-200
Stoichiometric air/fuel ratio (wt.)	6.4	9.0	14.6

Source: Ref. 7.9 as taken from 1977 issue of Technical Data on Fuel for all data other than blending RON.

Spark ignition engines presently in production can run on blends with a methanol content up to 3 percent by volume (M3) or an ethanol content up to 10 percent by volume (E10) with no effects on drivability or durability of engine and fuel system components. For higher methanol concentrations such as M10 to M15 it is usually sufficient to simply adjust the idle speed and mixture strength to prevent stalls. It was reported (Ref. 7.9) that some vehicles with carburettors adjusted to lean air/fuel mixtures in order to meet Australian emission standards suffered poor drivability (hesitating, surge, power fade on light acceleration) on M10 as a result of additional 'leaning-out' by the methanol. However, with enlargement of the carburettor jet, acceptable drivability was obtained for blends up to M25.

The air/fuel ratio for complete (stoichiometric) combustion is lower for methanol than for gasoline (Table 7.1). A blend of methanol with gasoline therefore requires less air for complete combustion than does gasoline alone. Since a carburettor controls the ratio of air to fuel, the consequence of passing a blend through a carburettor adjusted correctly for gasoline is the production of a leaner mixture than optimal for blend burning conditions.

Care must be taken that the blend of methanol and gasoline meets acceptable fuel specifications particularly with respect to critical properties such as octane numbers and volatility.

Methanol has a high octane number. However, the octane rating of a blend cannot be calculated from the simple average of the octane ratings of methanol and gasoline, weighted for composition. Methanol in the blend raises its octane rating more than this weighted mean would predict. This has given rise to the concept of 'blending octane' values (Table 7.1) which take account of such a synergistic effect (Ref. 7.10).

The octane number of a gasoline is determined by two different methods, the research and the motor methods, producing respectively the research octane number (RON) and the motor octane number (MON). Neither number fully reflects the tendency to pre-ignition in the engine in real operating conditions. Under full-throttle, high speed, heavy load conditions MON is the better indicator; under others RON is the more appropriate. The RON of a gasoline is significantly raised by blending with methanol; MON may be only slightly raised.

Methanol is a relatively low boiling compound (60 °C) but, more importantly, it forms low boiling point azeotropes with some of the hydrocarbon components of gasoline. Adding methanol to gasoline, therefore, appreciably raises the volatility of the fuel and increases the tendency to hot-fuel handling problems such as fuel line vapour lock and fuel starvation of engines when hot, or when re-starting after standing for a limited

period. This tendency can be overcome by removing some of the most volatile component (butane) from the gasoline at the refinery (Ref. 7.11).

Methanol has about half the calorific value of gasoline on a volume basis (Table 7.1) and, if that were the sole determinant, one litre of methanol would be equivalent to about 0.5 litres of gasoline. However, early work by Volkswagen suggests that an energy enhancement in the order of 3 - 5 % is obtained with a M15 blend (Ref. 7.9).

Other vehicle trials have shown a wide spread in results, a difficulty being that the effect being studied is smaller than the variations caused by different drivers and driving patterns and conditions. However, recent New Zealand vehicle trial data supports the existence of a energy enhancement effect with methanol blends (Ref. 7.11). The tests involved a wide range of vehicles, both pre-emission and emission controlled, under a variety of driving conditions with M5, M10, M15 and M25. These data suggest that a gasoline equivalence of 0.8 litres per litre of methanol should be allowed for vehicles not carburetted for lean burn and an equivalence not less than 0.6 allowed for emission controlled lean burn vehicles. The sense of the term 'gasoline equivalence' is readily shown using M15 as an example where

$$\text{gasoline equivalence} = \frac{\dfrac{\text{fuel consumption using gasoline}}{\text{fuel consumption using M15}} - 0.85}{0.15}$$

and where the fuel consumptions are expressed in litres per 100 km.

Material compatibility evaluations indicate that for M10 through to pure M100 a number of fuel system components require replacement. The most susceptible material/component combinations are plastic carburettor floats, plastic fuel lines and tanks, and rubber petrol pump diaphragms. Methanol can cause

crazing and cracking or even complete disintegration of some nylons, polyurethane and plasticised PVC. However, satisfactory alternatives such as certain nylons, high density polyethylene and teflon are available to the automotive manufacturers (Ref. 7.9).

Methanol and gasoline will mix in any proportions. However, if water is present the degree of miscibility is greatly reduced. If the miscibility limit is exceeded, two liquid layers are formed (phase separation). The lower (heavier) layer contains virtually all the water and most of the methanol, while the upper layer is almost all gasoline. A vehicle will not run on the water-methanol phase. With low blends of methanol the amount of water that can be tolerated is quite small (0.1 % in M15 at 20 °C). Evidence to date indicates that entry of moisture into normally capped vehicle fuel tanks is insufficient to cause phase separation. However, many older vehicles could have small quantities of water in fuel tanks which may require emptying. In most cases, however, the addition of a small quantity of a higher alcohol (for example 1 - 2 % isobutanol) to the blend will increase its water tolerance sufficiently (Ref. 7.10).

The suitability of ethanol as a gasoline blendstock and its method of production are discussed elsewhere in this report (Section 4.11).

Experience with ethanol blends is growing rapidly in Brazil where E20 is marketed commercially, although the vehicle fleet is somewhat atypical in that it consists mostly of air cooled Volkswagen cars previously operating on very low RON gasoline. Elsewhere, experience with E10 has been favourable - Ref. 7.12 reports a 2 - 3 percent increase in average energy economy for a fleet of 14 vehicles with a variety of engine sizes and emission control systems. As with methanol, the increase in energy economy is a consequence of the leaning of the air/fuel mixture by ethanol.

Ethanol can be produced from starch and sugar crops wherever there is suitable land and available water supply, but the major difficulty for most countries would be to provide sufficient land to produce significant quantities of ethanol without impinging on food and fibre production. Only countries such as Brazil with the potential for massive agricultural expansion can consider ethanol production as a major contributor to the liquid fuel supply.

When alcohol fuels are used in engines in a pure form or in high concentration blends (e.g. M90), maximum benefit is obtained by completely redesigning the engine to take advantage of the high research octane number. The compression ratio can be raised from about 9 to 1 up to 12 to 1, the ignition timing can be optimised and spark plugs with a suitable heat range choosen (Ref. 7.13).

Pure alcohols present cold start difficulties and a choice has to be made between using 85 - 90 percent alcohol with a 10 - 15 percent volatile gasoline component or making special design arrangements such as a pre-heater bowl attached to the carburettor for vaporising an initial charge of alcohol.

Ref. 7.13 reports on a Mercedes-Benz 280 SE designed to run on either M100 or E100. From the original 136 kW of the gasoline version the output rises to 146 kW with E100 und 150 kW with M100. The torque curve for the alcohols is displaced upwards almost parallel to the gasoline curve, and from 240 Nm at its best point with medium- grade gasoline is raised to 259 Nm for E100 and 270 Nm for M100. The minimum fuel consumption with E100 was 366 g/kWh and 491 g/kWh with M100 which, based on the net calorific values and densities given in Table 7.1, corresponds to efficiencies of 36.8 % for methanol and 36,1 % for ethanol.

Ref. 7.13 reports that 22 vehicles with 9 : 1 compression ratios have run on M100 as part of a fleet test carried out by Daimler-Benz and the West German Federal Ministry for Research

and Technology. The first vehicles have covered more than 60,000 km without any failure, but no final conclusion can be reached concerning durability until the end of 1982 or 1983 when the test is completed.

7.1.3 LPG and CNG cars

Liquefied petroleum gas (LPG) is a generic term covering the light hydrocarbons propane, propene, butanes and butenes, which are gaseous at normal temperatures and pressures but which are readily stored as liquids at normal temperature and moderate pressure (about 800 kPa), or at normal pressure at reduced temperatures (- 42 °C). LPG is a versatile but resource limited fuel with industrial, domestic and commercial heating applications and it is also an important chemical feedstock. Automotive use of LPG is at the expense of these other final demand sectors.

Natural gas which is essentially methane with small amounts of ethane, hydrocarbon gases and carbon dioxide can be stored in cylinders aboard vehicles as compressead natural gas (CNG). Cylinders typically contain a quantity of gas compressed at about 17 MPa and equivalent in energy content to about 12 litres of gasoline. The gas would occupy about 10 m^3 at atmospheric temperature and pressure.

Both LPG and CNG are in widespread use as gasoline replacement fuels, particularly in Europe where over one million cars and commercial vehicles operate on LPG and over a quarter of a million on CNG (Ref. 7.14). In Holland a network of some 2000 outlets supply more than 500,000 tonnes of LPG to about 350,000 vehicles, private and commercial. In Italy more than 750,000 tonnes of LPG are distributed to over half a million vehicles and about 250 fuelling stations distribute CNG to about quarter of a million vehicles.

Both LPG and CNG demonstrate similar vehicle performance characteristics and can be used in spark ignition engines with modification to the fuel storage and fuel line systems. Engines need not be modified, although the high octane ratings of these fuels are better suited to high compression engines (up to 12:1). Because of the gaseous nature of the fuels, engine life of converted gasoline vehicles will be significantly extended, with engine wear, spark plug and oil deterioration substantially reduced (Ref. 7.14).

Penalties incurred with conversion to gaseous fuels are slight power losses and slightly increased acceleration times. The gaseous nature of CNG results in reduced on-vehicle storage in comparison to gasoline. This results in a reduced vehicle range of between 30 - 50 percent of gasoline vehicles. Storage cylinders of both CNG and LPG intrude upon the trunk space of cars.

Both gaseous fuels are unleaded and this may cause some valve and valve seat wear under high load conditions but this can be rectified by the use of hardened valves and valve seats.

Diesel engines can be operated on both CNG and LPG, although such conversions are not as popular as spark ignition engine conversions and normally require a diesel blend for fuel ignition. Ignition still depends on the existing fuel injection system and gaseous fuel is then aspirated into the combustion chamber through the air intake. For LPG it is common to convert diesels only for heavy load operation, typically above 60 percent of full load because of rough handling and a drop in thermal efficiency at lower load operation. While power output can be maintained for dual fuel operation (diesel/LPG) penalties are incurred with fuel consumption which commonly increases by about 10 percent (Ref. 7.14).

Compression ignition engines will perform very well on a CNG/diesel mixture in terms of power output and fuel consumption. However on a large diesel powered vehicle up to 10 gas cylinders each weighing 50 kg and holding the energy equivalent to 8 to 10 litres of diesel oil would be required to give only a range of about 80 km (Ref. 7.14). Despite such limitations, short haul diesel vehicles may have some potential for conversion to CNG if gas supply, payload and cylinder fitting constraints can be met.

In summary, the vehicles most suitable for conversion to gaseous fuel, particularly CNG, will be those of limited gross vehicle weight (less than 5 - 7 tonnes) and travelling on short-to-moderate length well-defined routes where there is availability of refuelling outlets capable of providing gas compressed to 17 MPa. The cost of conversion to gaseous fuel is generally only economic for vehicles expected to have high operational usage (above say 20,000 km/a) and if the price differential of the gas below gasoline is significant. Conversion costs in some countries are substantial; currently in Australia they are of the order of $ 800 to $ 1150 (1980 $ US) for gasoline vehicle conversions and $ 1700 to $ 2300 for diesel vehicle conversions. However, experience in Italy indicates that these costs can be lowered (see Section 7.1.5). Costs vary for CNG and LPG depending on the number of cylinders fitted, the size of the cylinders and the type of vehicle converted.

7.1.4 The Electric Vehicle

Electric vehicles (EV) and electric hybrid vehicles (EHV) presently available, or under development, are more limited in terms of range, speed and acceleration and less convenient in terms of refuelling (battery recharging or exchange) than conventional internal combustion engine vehicles (ICEV). However, EVs have a number of very significant advantages. They shift pollution control responsibility to the central power

stations where abatement measures are likely to be most cost effective, they are quiet, and they offer significant opportunities for switching from petroleum to more abundant fuels suitable for electricity generation. In addition, EVs have lower operating and maintenance costs (excluding battery replacement) than ICEVs and longer lives (more than double those of conventional vehicles).

Despite their current limitations, EVs have a potential in a variety of transportation modes. It has been repeatedly demonstrated that in specialised applications such as slow-speed, short-range delivery vehicles, forklifts and underground tipper trucks, EVs have operational and environmental advantages despite their high relative capital cost. The EV, for example, appears to be suited to town centre bus operation where there are frequent stops and the speed required between stops is not high.

The potential for the electric car to penetrate the passenger car market in any particular country must be considered within the context of national urban development structure and vehicle usage patterns. There are opportunities for EVs to become the 'second car' for families in affluent countries where multicar ownership by households is the norm. Such households often desire a vehicle for short intra-urban trips as well as longer non-urban trips. Ref. 7.15 suggests that existing EVs with a 60 km range could be used for over 90 percent of all U.S. trips. An EV with a 160 km range could satisfy almost all of the local travel needs of multi-car households and business fleets. Such a vehicle could be available during the 1980s, given expected improvements in car and battery design.

Performance standards promulgated in 1978 (Ref. 7.16) are now being met by some currently available EVs. These standards for passenger cars called for

a) acceleration from 0 to 50 km/hr in less than 13,5 sec.;
b) the ability to climb grades of 10 percent at a constant speed of 25 km/hr;
c) the ability to climb grades of 20 percent for up to 20 sec.;
d) forward speed of 80 km/hr for 5 min.;
e) range of 55 km for the C cycle of SAE Standard J227a for an EV and 200 km for an EHV;
f) non electrical energy consumption of no more than 1.3 MJ/hr for EHVs; and
g) recharge time from 80 percent discharge of no more than 10 hr.

Commercially available vehicles achieving these standards employ lead-acid batteries and series or separately excited direct current (d.c.) motors. Some vehicles include regenerative braking where the work done in braking is not lost to heat in the brake pads but returned as electrical energy to the battery. Motor speed control is generally achieved by thryristor choppers in the armature circuit. Many EVs have direct drives and no transmission, although some have automatic or manual shift transmissions. It should be noted that EVs can have great acceleration and very high top speeds but at the expense of range, cost and efficiency. A tradeoff of these factors in existing vehicles has usually resulted in modest acceleration and just adequate top speeds (Ref. 7.15).

A state-of-the-art EV is typified by the U.S. Department of Energy electric test vehicle, ETV-1 unveiled in June 1979. This EV has a low drag coefficient and employs low rolling resistance experimental tyres. Lightweight materials such as aluminium and plastic are used for body parts and windows. ETV-1 is equipped with experimental lead-acid batteries, separately excited d.c. motor, transistor power conditioning unit for field chopping, armature chopping and micro processor control of energy flows. The cost goal for the development was $ 8000 in 1980 US $ (Ref. 7.15).

Performance of ETV-1 showed an acceleration of 8.8 sec. for 0 to 48 km/hr, a top speed of 110 km/hr, and ranges of

200 km at 56 km/hr;
145 km at 72 km/hr; and
120 km for the SAE J227a D urban cycle.

Of the battery systems being developed for EVs, major efforts are concentrated on the following systems: advanced lead-acid, nickel-iron, nickel-zinc, aluminium-air, iron-air, zinc-chlorine, zinc-bromine, lithium-metal sulphide and sodium-sulfur (Ref. 7.17). The first three of these battery systems are candidates for near term application.

Tentative goals for EV batteries are (Ref. 7.17):

a) duty cycle of 2 - 4 hour discharge, 1 - 6 hour charge;
b) specific energy greater than 140 Whr/kg;
c) specific sustained power greater than 70 W/kg;
d) specific peak power (15 second peak at 50 percent state of discharge) greater than 200 W/kg;
e) cycle life greater than 1000 deep discharges; and
f) cost of about $ 50/kWhr.

As an indication of progress towards these goals results achieved by 1980 with nickel/zinc were (Ref. 7.17):

a) specific energy of 71 Whr/kg;
b) specific peak power of 120 W/kg; and
c) cycle life of 180 cycles.

7.1.5 Passenger Cars - Characterization Summary

Australia provided several characterization for a medium sized passenger car of test mass and engine capacity typical in the Australian car fleet of the late 1970s -early 1980s. The vehicle was powered by a spark ignition (otto) engine and alternative fuels considered were gasoline, LPG, pure methanol (M 100), and pure ethanol (E 100). Assuming the same mass and engine size as the Australian vehicle, a characterization of a spark ignition car running on a M 15 methanol-gasoline blend was provided by the KFA Operating Agent.

Australia also submitted a characterization for a medium sized electric passenger car.

Two characterization came from Italy for the conversion equipment to be added to a small spark ignition vehicle to allow it to be run on LPG and CNG.

Key economic and technical parameters extracted from these data are presented in Table 7.2. The information on conversions of vehicles to operate on CNG and LPG provided by Italy is discussed in parallel with the Australian LPG car data in the notes to the table.

TABLE 7.2 - Technical and Economic Key Data of Passenger Cars

	Task Specific Energy Consumption	Drive Efficiency	Total Capital Cost	Total O&M Cost	First Commercial Year	Economic Lifetime
	MJ/km	%	$	$/y	Year	
A. Spark ignition, 4 cylinder, 2 litre engine. Vehicle test mass 1300 kg. Standard work requirement of drive cycle 0.43 MJ/km. Vehicle fuelled by/assessment by:						
Gasoline - Australia	4.12	10.4	7770	730	c.a.	10
LPG - Australia	3.42	12.6	8800	730	c.a.	10
M15 - KFA Operating Agent	3.98	10.8	7800	730	c.a.	10
Methanol - Australia	3.34	12.9	9140	730	1985	10
Ethanol - Australia	3.95	10.9	9140	730	1985	10
B. Electric vehicle (70 kW) with test mass 1600 kg. Standard work requirement of drive cycle 0.43 MJ/km - Australia	0.6	71.7	18300	1080	1990	20

c.a. = currently available

Assessors

Australia: - Musgrove, A.R., AAEC, Lucas Heights Research Laboratories, Private Mailbag, Sutherland, N.S.W., 2232

Italy: - Tosato, G.C., Ente Nazionale Idrocarburi, Piazzale Enrico Mattei 1, Rome.

KFA Operating Agent: -
Maher, K. KFA/STE Jülich, Postbox 1913,
D-5170 Jülich, FRG.

Notes

1) Heating Values of Fuels.
The original Australian data for gasoline and LPG vehicles were derived using gross calorific values (GCV). The data were recalculated on a net calorific value (NGV) basis for the purposes of Table 7.2 using the following heating values (Refs. 7.18, 7.19):

	GCV (MJ/kg)	NCV (MJ/kg)	Density (kg/litre)
Gasoline	47.14	44.8	0.736
LPG	50.00	47.7	0.521

The Australian data for alcohol vehicles were derived using NCVs for methanol and ethanol somewhat different from those given in Table 7.1. The values used (Ref. 7.20) were:

	NCV (MJ/litre)	Density (kg/litre)
Methanol	15.6	0.791
Ethanol	20.8	0.789

The NCV used in the M 15 characterization was from Table 7.1.

2) Task Specific Energy Consumption. The original Australian data were presented in units of MJ/passenger-km, but in all cases the occupancy of the vehicle was considered to be two persons, adding 100 kg to the unloaded 'curb' mass.

The Australian assessor provided a number of general references including Refs. 7.21, 7.22 and 7.23 for internal combustion engine vehicles and Refs. 7.24 and 7.25 for electric vehicles. The methanol vehicle characterizations (M 15 and

M 100) drew upon Refs. 7.10 and 7.11. For the M 15 vehicle a gasoline equivalence (see Section 7.1.2) of 0.7 was assumed for the blend.

Fuel consumption rates by volume corresponding to the energy consumption rates given in Table 7.2 were:

	Consumption (litres/100 km)
Gasoline	12.5
LPG	13.75
M 15	13.09
Methanol	21.4
Ethanol	19.0

3) Drive Efficiency. Calculated as:

standard work requirement / task specific work requirement

4) Total Capital Cost. The average price of a 1980 model 4 cylinder 2 litre gasoline car in Australia (including a significant tariff component) was
A $ 6800, or US $ 7770.

The cost of converting the same on-the-road gasoline car to LPG operation is US $ 1030. An LPG (or possibly dual fuel) car might be produced on the assembly line for about an extra US $ 600 above the gasoline car cost.

The Italian assessment of the cost of converting a small 1.3 litre vehicle to dual LPG/gasoline operation was:

	US $
LPG storage tank	50
Other equipment	100
Labour costs	180
	330

with 10 percent confidence limits of $ 300 and $ 350. 'Other equipment' refers to LPG fuel lines, electric valves to control gasoline and LPG

flow, a water cooled reducer which by pressure loss and heat absorption from the car's water cooling circuit gasifies the LPG, and a fuel mixer. The additional mass of the tank and equipment is 35 kg.

It is of interest to compare the LPG conversion cost with the costs also provided by Italy for conversion of a similar 1.3 litre vehicle to dual gasoline/CNG operation.

Here the conversion cost breakdown is:

	US $
3 aluminium or steel storage tanks	700
Other Equipment	120
Labour Costs	180
	1000

The mass of the 3 CNG tanks, each designed for a maximum pressure of 22 MPa, is 70 kg if constructed in aluminium, or 100 kg if in steel. 'Other equipment' refers to valves for dual fuel operation, switches, manometer, water cooled methane reducer and fuel lines. The assessor notes that, if the engine is run only on CNG, the efficiency of the vehicle is 1.15 to 1.2 times that of a corresponding gasoline car.

The costs of converting a car to M 15 operation are trivial, consisting only of replacement of fuel line components likely to be affected by methanol with alternative materials of similar cost.

The high cost of the electric car is based on present day values which represent low volume production of vehicles barely advanced from prototype status. Other sources (e.g. Ref. 7.15) which perhaps err on the other side towards optimism indicate a large volume production cost about 20 percent greater than that of equivalent conventional vehicles.

5) Operating and Maintenance Costs. For internal combustion engine vehicles the estimated costs are broken down as follows:

	$ US per year
Tyres	208
Service, repairs, vehicle damage	382
Road repairs etc.	140
	730

For the electric vehicle O&M estimated costs break down as follows:

	$ US per year
Tyres	100
Service, repairs vehicle damage	300
Battery replacement	540
Road repairs etc.	140
	1080

Battery replacement cost corresponds to a complete replacement of the battery pack every three years for $ 1620.

7.2 Unit Trains

A unit train is a complete train dedicated to transporting minerals directly from a loading point at a mine to an unloading point and returning empty. There are obvious savings compared with conventional methods where trains carrying mixed commodities are made up and subdivided in marshalling yards. Among their different cargoes, unit trains have hauled mainly coal, iron ore and phosphate.

An advantage of unit trains is that they can be loaded and unloaded rapidly without uncoupling. The type of car (wagon) can be hopper, gondola, tank or covered. The rotary dumper is a proven method of rapid unloading, averaging 35 cars per hour.

A typical unit train might consist of 100 to 130 loaded cars headed by five or six locomotives with a caboose behind - a total weight of more than 16,000 tonnes.

Three characterizations were received from Australia of locomotive types suitable for hauling iron ore unit trains from mines in the Pilbara region of North West Australia to coastal loading facilities. The types considered were diesel-electric, electric and the unproven technology of dual injection, methanol/diesel - electric. These locomotive types are discussed in sections 7.2.1, 7.2.2 and 7.2.3 and Australian characterizations are summarized in section 7.2.4.

7.2.1 Diesel Locomotives

The displacement of coal fuelled steam locomotives by diesel traction over the past 40 years was almost total. There are even instances of large investments in main-line electrification in the USA and elsewhere being abandoned in the face of the economic advantages of diesel locomotives. Attractive features of the diesel are listed in Ref. 7.26 as follows.

a) Relatively low capital cost attained from the use of standardised designs and mass-produced components by the main manufacturers.
b) High overall thermal efficiency of about 25 %, well-sustained through the useful power output range.
c) High reliability. Ref. 7.26 quotes failure statistics for the 2240 kW L-class diesel units operated by Western Australia's Westrail for passenger, grain and mineral traffic. An in-service failure that prevents or delays a unit from completing its rostered journey occurs on average only once every 54,000 km.
d) Flexibility in traffic. The same diesel unit can efficiently work different kind of train. 'Multiple-unit' operation by one driver, allows power to be economically tailored to traffic demand.
e) Availability for traffic. Availability is over 90 % with well-proven models and good maintenance.
f) Low maintenance demands. Ref. 7.26 provides some specifics for the L class diesel units operated by Westrail. They run typically 12,000 km in a month, and achieve 25,000 km before they require scheduled mechanical examination beyond refuelling, sanding, liquid-levels and safety checks. Only at 75,000 km intervals is the diesel engine throroughly examined. Wheels last 400,000 km before replacement, when traction motors are also overhauled. Not until then does the locomotive have to be lifted off its bogie. The diesel locomotive will run typically 900,000 km (18,000 engine hours) before its cylinder heads are removed for overhauls that involve removing pistons and cylinder liners.

Increases in specific output of rail traction diesel engines have been and will be attained by increased turbocharging and intercooling. Motivation for engine uprating will come from the need for low specific weights in high-speed service. The penalties for uprating will be increased maintenance demands and only better design, new materials and more sophisticated preventive maintenance practice will keep wear rates at the levels achieved by operators of the present more conservatively rated engines.

Nevertheless, over the next 20 years world railways will be well placed to use all the power that the engine manufacturer can reliably build into locomotives engined by a single medium-speed diesel. Powers could rise from the typical 2000 - 2500 kW main line range to 3500 kW in the late 1980's using uprated 18 to 20 cylinder versions of existing engines, and then rise again by the year 2000 to perhaps 4500 kW with a completely new generation of diesel engines.

Ref. 7.26 notes that quick-running (1500 rev/min or above) diesel engines are used in regular heavy freight or mineral traffic in the USA, Brazil and the Soviet Union. However, the reduction in mass is at the expense of having the period between overhauls falling to about 5000 hours. In contrast, the throroughly developed medium speed diesel engine routinely achieves 15,000 - 25,000 hours between major overhauls. On the other hand, the relatively compact and portable quickrunning engine favours convenient unit-exchange of repaired, bench-tested engines thus reducing locomotive outage time. But there is no great incentive to develop such an engine for the major railways because the higher specific mass of the wellregarded medium-speed engine is no disadvantage with North American axle-loads. The wide spread application of the quick running diesel before 1990 is therefore unlikely.

7.2.2 Alternative Diesel Locomotive Fuels

Ref. 7.26 notes that a possible engine development is a multi-fuel variant of an established compression-ignition engine to burn both liquid and gaseous fuel. Natural gas is readily burned in a dual-fuel diesel engine modified for the admission of gas into the induction manifold and to initiate and sustain combustion by the constant injection of around 5 % of the equivalent full power volume of diesel fuel. Most natural gas applications to data are slow-speed 4-cycle stationary engines powering generators or pumping sets. Medium-speed diesel engines should be suitable for similar modifications, but no

locomotive is known to be running with a dual-fuel diesel. The development effort and extra handling and maintenance complications could become economically acceptable as preferred liquid fuels become more expensive.

A considerable literature exists on experimental dual fuel operation of small diesel engines with diesel oil and methanol or ethanol. By comparison, experience with diesel fuel/methanol blends in large compression-ignition engines is very limited. Reference 7.27 describes the operating characteristics of a 450 kW, 4-stroke, six cylinder, turbocharged locomotive diesel-electric engine running on diesel/methanol blends. A comparison of the results obtained in this work and those obtained in similar experiments with smaller engines indicate that, the larger the engine, the more critical is the compromise with an adequate compression ratio that allows diesel combustion without methanol detonation.

Reference 7.27 summarises that in diesel engines running with fumigated fuel into the intake manifold, alcohol combustion is very critical, varying between auto-ignition (Otto type detonation) at high loads, and incomplete burning with low efficiency and methanol quenching with ignition delay and Diesel type detonation at low loads.

7.2.3 Electric Locomotives

The electric locomotive is the main alternative to the diesel at present; the European and Japanese railways are substantially electrified.

The viability of rail electrification depends on large efficient power stations being located within several hundred kilometers of railway substations. This condition is not met in many parts of North America and Australia, for example. For the next 10-15 years, and pending further developments in ultra high voltage, direct current transmission technology, the prospects for railway electrification seem limited by the

economics of transmitting alternating current within a range of say 500 km of a low cost energy source.

Reference 7.26 lists the following advantageous features of electric traction.

a) The possibility of using locally-available non-oil energy sources without having to develop new locomotive technologies (e.g. dual-fuel diesels, gas turbines).
b) The ability to exceed substantially the continuous rating of the locomotive for short periods when accelerating or climbing short gradients.
c) High energy conversion efficiency of about 90 % for the locomotive and over 25 % for the complete power station/transmission/locomotive system.
d) Good locomotive availability of almost 95 %.
e) Reduced maintenance demands and costs. Various authorities put these at 50 to 65 % of equivalent diesel costs. Engine-dicated diesel locomotive overhauls typically occur at 500,000 - 900,000 km intervals. European electric units have doubled this performance.
f) High power-to-mass ratios that are well suited to intensive and/or high-speed passenger services, particularly on heavily graded lines. This is not such an important consideration for unit freight trains.
g) Energy economies from regenerative braking.
h) Freedom from diesel exhaust pollution and easier control of emissions from stationary power plants.

The major disadvantage of electric traction is the high capital cost of the fixed substations and the overhead system (catenary and supporting towers). Another disadvantage is the cost of immunising signalling and telecommunications circuits from electrical interference.

The standard voltages for which there are both well developed equipment and a base market for future technologies are

- 20 kV (Japan)
- 25 kV (internationally used and virtually the existing AC standard), and
- 50 kV (a fairly recent US development).

Ref. 7.26 presents a very wide range of electrification cost estimates ranging from $ 37,000 to $ 220,000 (1980 $ US) per single track kilometer of 25 kV AC overhead (including apportioned substation cost). The upper value is for a complex, sharply curved urban system with many intruding structures and difficult clearance problems.

To these mainline costs one must add costs for electrical shielding for signal and communications (immunisation), overhead system premiums for bridges and tunnels, overhead system in yards and sidings, grid connection cost, and overhead system maintenance costs.

7.2.4 Heavy Duty Locomotives - Characterization Summary

Australia provided three locomotive characterizations. These are summarized in Table 7.3.

TABLE 7.3 - Technical and Economic Key Data of Heavy Duty Locomotives

Locomotive Type	Engine Size	Task Specific Energy Consumption	Drive Efficiency	Total Capital Cost	Fixed O&M Cost	Economic Lifetime
	kW	MJ/ net t-km	%	$/kW	$/kW	Years
Diesel-electric	2685	0.126	26	410	19.1	20
Methanol/diesel-electric	2685	0.117	28	421	24.6	20
Electric	3800	0.035	95	447	9.5	30

Assessor

Australia: - Musgrove, A.R., AAEC, Lucas Heights Research Laboratories, Private Mailbag, Sutherland, N.S.W., 2232

Notes

1) Engine Size

Diesel Locomotive is the Co-Co type M636 built by Commonwealth Engineering Co. (Australia) - American Locomotive Co. (USA)

General Electric Co. (USA). Mass 190 t, axle load 310 kN as operated on the Pilbara iron ore railways.

Methanol locomotive is hypothetical M 636 type with modified engine and dual methanol/diesel injection system.

Electric locomotive can be regarded as AC traction equipment on the deck of an otherwise standard Co-Co diesel electric freight unit (following current North American design approach). Such an approach (Ref. 7.26) would produce, within axle loads slightly reduced from those of the equivalent 2685 kW diesel electric, a 3800 kW, 120 km/h, Co-Co electric locomotive that would show improvement on the diesel's adhesion. While probably not the optimum locomotive, it would safely restart the heaviest existing ore trains. On these trains the electric unit would replace the diesel one-for-one and would haul the trains uphill at faster speeds. On lighter, faster mixed freight trains two electrics would comfortably replace three diesels.

The European approach to replacing the diesel unit train locomotives would be based on the short train philosophy, inclining towards a low cost standard 4-axle mixed traffic electric locomotive, with all components developed from scratch for electric use.

2) Task Specific Energy Consumption

The energy consumption rate of locomotives depends strongly on the task achieved.

The unit trains presently hauled by diesel-electric locomotives in the Pilbara consist of 3 locomotives drawing 184 ore-cars. Each car carries about 100 tonnes of ore. The methanol/diesel - electric locomotive described is suited to execute the same task. However, the electric locomotive described would be used in 3 loco, 152 car combinations, the

higher speeds and turn-around of an electrified system saving ore cars. Car loads would still be 100 tonnes.

The diesels on the Pilbara lines haul 23,000 t gross up 0.3 % grades and dynamically brake it down 2 % grades. The units average 50 km/h with these trains, which are among the world's heaviest and which approach the rated maximum tonnage of the locomotive. The duty cycle involves 60 % more full-throttle operation than the North American main lines for which the M 636 was originally developed.

The task specific energy consumption (TSEC) value given for the diesel-electric locomotive was calculated by the assessor on a gross calorific basis from

$$\frac{\text{litres of fuel used per round trip X 38.3 MJ/litre}}{\text{length of one way trip X tonnes of iron ore moved per trip}}$$

to give a value of 0.133 MJ/net tonne-km. For Table 7.3 the TSEC was recalculated assuming a NCV for diesel oil of 36.3 MJ/litre (Ref. 7.19).

Unit trains moving coal in Queensland over the Great Dividing Range to coastal ports against grades no greater than 1 % obtain, on a similar basis, about 0.23 MJ/net tonne-km, and against greater than 2 %, 0.3 MJ/net tonne-km. By comparison Ref. 7.28 gives as a rough guide a task specific energy consumption for USA coal unit trains of 0.28 MJ/net tonne-km. Ref. 7.29 indicates that in the U.K. for fully laden merry-go-round trains and whole trainloads 0.35-0.45 MJ/net tonne-km can be achieved, though the average performance is lower.

The TSEC for methanol/diesel-electric locomotives was calculated by the assessor from

$$\text{TSE (methanol)} = \frac{\text{TSEC (diesel) X drive efficiency (diesel)}}{\text{drive efficiency (methanol)}}$$

to give a value of 0.12 MJ/net tonne-km. Since the assessor, in fact, used a NCV for the methanol component (90 % by volume) of the input to the dual fuel locomotive, the TSEC has been recalculated to be 0.126 MJ/net tonne-km (26/28).

TSEC (electric locomotive) was calculated in a similar way.

3) Drive Efficiency

Little experience has been accumulated with large methanol fuelled diesel engines. Smaller plant such as the spark-assisted M.A.N. FM bus engine (Ref. 7.30) running on methanol have shown equivalent or lower operational efficiencies than equivalent diesels operating on standard fuel. However Ref. 7.31 reports on investigations with an air-cooled, turbocharged, hig-swirl open-chamber, single cylinder diesel engine with methanol direct injection. The efficiency of the alcohol dual fuel engine was equal to, and at low engine speeds and high load, even considerably better than the conventional engine. The superiority of the methanol engine in the low speed range was advanced in Ref. 7.30 as a reason for increased methanol consumption in the M.A.N. bus - drivers used faster acceleration in the stop and go pattern of urban traffic.

4) Assessor gives capital cost of diesel-electric locomotive in 1980 $ US as $ 1.1 * 10^6 with 10 % probability of being greater than $ 1.5 * 10^6. Converting 1976 $ Aust. cost of $ 750,000 for a M 636 locomotive (Ref. 7.26) to 1980 $ US gives $ 1.2 * 10^6. To arrive at the capital cost of the methanol/diesel-electric locomotive, the assessor adds to the diesel-electric locomotive capital cost given above $ 25,000 for a dual fuel injection system.

For the capital cost of the substitutable electric locomotive the assessor gives $ 1.7 * 10^6. Converting minimum 1976 $ Aust. cost of $ 1.1 * 10^6 for such a unit (Ref. 7.26) to 1980 $ US gives $ 1.76 * 10^6.

5) Total O & M Costs

For the diesel-electric locomotive the assessor estimated annual O & M charges of $ US $ 51,300, based on $ 0.285 per train-km annum with one major overhaul every 4 years. This can be compared with Ref. 7.26 which gives $ 62,000, on converting to 1980 $ US.

For the methanol/diesel-electric locomotive the assessor estimated annual O & M charges of $ 66,000 with a 10 % probability of being less than $ 55,000.

For electric locomotives travelling on an iron ore railway with 1000 km under wire a locomotive O & M cost of $ 26,000 and an overhead and substations O & M cost (per locomotive) of $ 10,000 was assigned. For this railway Ref. 7.26 gives a value of $ 38,400 for electric locomotive O & M costs on converting to 1980 $US, and a value of $ 12,600 for annual O & M costs per locomotive for catenary electrification.

7.3 Container and Bulk Cargo Ships

At present, about 4,5 % of annual world oil production is consumed in ship engines, predominantly in those of large bulk cargo carriers. Oil itself provides the largest tonnage of sea-borne bulk cargo. The world fleet at July 1981 consisted of 172 million tons gross (Mtg) of oil tankers, 113 Mtg of ore, bulk and bulk/oil carriers, and 102 Mtg of container, general cargo and specialized carrier ships (Ref. 7.32).

Smaller tonnages of general sea cargo are moved, usually in standard sized containers. A common container size is 20 * 8 * 8 cubic feet, typically holding about 20 tonnes of cargo. Container traffic is often measured in terms of this unit; that is, in terms of the 'twenty foot equivalent unit' or T.E.U.

Almost every cargo ship is powered by an oil fuelled engine, either a marine diesel or a boiler/steam turbine cycle. Over 200 naval ships are nuclear powered but for operational rather than economic reasons. Coal has been almost totally displaced by oil as the motive power source for ships during this century. In 1926 only 5 % of the world tonnage was oil fuelled. By 1936 it was 19 % and in 1979 95 % of the total tonnage registered.

However, the situation now is that the fuel cost has escalated to such an extent that fuel oil and diesel oil represent in some cases 40 percent of operating costs. This has resulted in many ships steaming at well below designed speed to reduce fuel costs (as an approximate rule, power requirements are proportional to the cube of the ship's speed). Opportunities for coal, coal/oil slurry or gas fired ships have therefore appeared.

Specific power requirements and hence specific fuel consumption rates of marine engines fall significantly as the size and capacity of the ship increases. Capacity is normally measured in deadweight tonnes (dwt), the difference in tonnes between a ship's displacement fully laden and its displacement at light draft; thus capacity comprises cargo, fuel, stores, water etc.

Ref. 7.33 indicates a typical specific power of about 1.3 kW/dwt for a container ship and less than 0.2 kW/dwt for a large oil tanker or bulk carrier.

Australia has provided characterizations for conventional oil fuelled coastal container ships powered by either diesel or steam turbine (Section 7.3.1) and for a coal fired steam turbine bulkship (Section 7.3.2) suitable for coastal or long distance hauls. Key economic and technical data from the characterizations are summarized in Section 7.3.3.

7.3.1 Oil Fuelled Ships

Below a shaft power (power delivered to the propeller) of 11,000 kW the diesel is almost always the only power plant used in commerical craft. The diesel has a lower fuel consumption rate than the steam turbine. Other advantages are its quick starting, stopping and securing which reduce standby losses.

A typical slow speed (two stroke) marine diesel with a brake power of 11,000 kW at 115 rpm will have 12 supercharged cylinders each with bore diameters of 90 cm., and strokes of 150 cm.. Total engine weight can be on the order of 1,000 tonnes.

Large slow speed direct drive diesels are used as well as medium speed diesels driving propellers through 2 : 1 or 3 : 1 reduction gears, with flexible couplings installed between engine and gear pinions to absorb variations in torque, thus preventing vibrations.

The main developments in future marine diesel machinery will take further advantage of improved turbocharger efficiencies and the possible introduction of two stage turbocharging to increase the turbocharger pressure ratio from the current

values of 3.5 to 1. Design improvements will permit the uprating of machinery so that the output per unit length and unit weight will be increased but it is expected that this can be done without increasing the ratio of maximum pressure to mean pressure significantly. The specific fuel consumption will therefore remain basically at the current level of 216 g/kWh when burning marine fuel oil (Ref. 7.33).

The majority of existing ships' equipment has been designed to operate on intermediate marine fuel grades, generally in the kinematic viscosity range 180 - 200 centistokes (cst) at 50°C. However, in the more modern ships, with large bore, slow-speed diesel main propulsion engines, the tendency has been to use heavier grade fuels, typically up to 400 cst at 50°C. (Ref. 7.32).

The other main contender for marine propulsion is the steam turbine. Two main types of steam turbine design now predominate: the cross compound single plane design with axial flow condensers and the multiplane design with underslung condensers.

The design of steam boilers is influenced to a great extent by the need to reduce maintenance costs, in addition to the usual aims of high output and increased boiler efficiency. Main propulsion water tube boilers now have evaporation capacities of 75,000 - 130,000 kg/hr, with design pressures of 6,500 - 7,500 kPa and super heater outlet temperatures of about 510°C (Ref. 7.34).

The basic technology for increasing the output from steam turbine designs is already available and can be achieved with little increase in the size of the plant. Two basic types of cycle are expected to emerge (Ref. 7.33), the first and simplest (the straight Rankine cycle) being for the higher power ranges. Installations of this type will be based on twin boilers with steam conditions of 6,300 kPa and 510 °C. Three feed-water heaters, including one in the high pressure part of

the feed-water system would give a service fuel consumption of 280 g/kWh at 29,420 kW burning a heavy marine fuel oil.

The second type of installation would be based on a re-heat cycle with twin boilers and steam conditions of 10,100 kPa and 510°C. The remaining features would be basically as described above, except for the use of five feed-water heaters in the cycle, giving a fuel consumption of 255 g/kWh. under anticipated operating conditions.

7.3.2 Coal Fuelled Ships

The first coal-fired vessel to be built for a quarter of a century, the 75,000 dwt Panamax sized 'River Boyne', has been launched at the Mitsubishi Heavy Industries Ltd. yards for the Australian National Line (ANL) and, as of July 1982, there were ten of this modern breed of steamship in order or being constructed in yards around the world (Refs. 7.35, 7.36). Mitsubishi is building a sister ship to the 'River Boyne' for ANL and the Italian firm, Italcantieri is constructing two similar vessels for the firm Bulkships Container Pty. Ltd. All four ships will be used on the same bauxite coastal run (Weipa to Gladstone) by ANL.

ANL's vessels have two Mitsubishi - Combustion Engineering V2M - 9s main boilers, arranged solely for coal firing supplying steam to turbines capable of developing an output of 14,000 kW. The boilers are steamed at all times at sea and in port.

The handling of coal from the bunkers to the daily service hoppers just above the boilers is achieved by a pressure pneumatic system, applied for the first time to a shipboard installation. Fly ash is separated from the flue gases and clinker ash and, after crushing, is fed from collection hoppers to ash storage tanks also by a pneumatic system. The IMCO Convention on the Pollution of the Sea by Ships has placed large areas of world seas and oceans off-limits for the discharge of solid material. Therefore ash storage is essential (Ref. 7.37).

The Bulkship design has only one main boiler. This is a Franco Tosi built, Combustion Engineering stoker-fired water tube design, capable of oil firing. The boiler provides steam to a General Electric cross-compound turbine with a shaft power of 14,200 kW. The service speed will be about 15 knots (27.8 km/hr) requiring a daily coal consumption of 220 tonnes.

A contract for a single coal fired bulk carrier was placed in 1981 by New England Electric Co. in the USA with the General Dynamics Quincy shipyard. The first ocean going coal burner to be offered in the USA for 30 years, it will haul bunker coal to the owner's power stations. It is likely that coal ships will be dedicated to specific shuttle routes until bunkering and ash disposal facilities are widespread in ports around the world.

The New England Electric ship is about 37,000 dwt with a 9,000 shaft kW turbine supplied with steam driven by two Foster Wheeler Corp. boilers each producing 20 tonnes/hr of steam at 6000 kPa and 480°C. The boilers are arranged for either coal or bunker C heavy fuel firing up to maximum output (Ref. 7.36).

A coal-firing conversion project being undertaken in Spain at the El Ferrol shipyard of Empresa Nacional Bazan for the state shipping line ELCANO involves the replacement of one of the twin oil fired boilers in each of two 190,000 tonne turbine oil tankers by a Combustion Engineering type V2M - 9s coal fired boiler rated at 80 to 92 tonnes/hr steam (Ref. 7.32).

The main disadvantages of coal fired ships are the 10 - 15 % increase in capital cost over a diesel equivalent and the loss in cargo capacity resulting from the higher volume of fuel that must be carried. The increase in capital cost occurs because of the additional plant required and the new technology. The cargo capacity loss can be assessed from the fact that about two a half tonnes of coal are required to replace a tonne of oil in the bunkers.

7.3.3 Container and Bulk Cargo Ships - Characterization Summary

Australia provided three ship characterizations. These are summarized in Table 7.4.

Table 7.4 - Technical and Economic Key Data of Cargo Ships

Ship Type	Shaft Power	Task Specific Energy Consumption	Energy Consumption	Total Capital Cost	Total O&M Cost	Economic Lifetime
	MW	MJ/ net t-km	GJ/h	$ x 10^6	$ x 10^6	Years
Coastal container vessel - diesel		0.17	52.4	16	4.5	20
Coastal container vessel - steam turbine, oil fired		0.213	65.3	16	4.5	20
Bulk carrier - steam turbine, coal fired	14.2	0.093	188	46	5	20

Assessor

Australia:- Musgrove, A.R., AAEC, Lucas Heights Research Laboratories, Private Mailbag, Sutherland, N.S.W., 2232

Notes

1) Shaft Power

The assessor gave the output of the coal fired steam turbine as 19,000 shaft horsepower but did not give engine outputs for the two container ships. These ships have a nominal container capacity of 650 T.E.U. (i.e. probably about 13,000 dwt), steam at 18 knots (33 km/hr) and might be expected to have engines delivering about 6 MW to the shaft.

2) Task Specific Energy Consumption (TSEC).

The assessor has based his TSEC calculation on the following assumptions:

The steam turbine container ship burns 35 tonnes of heavy fuel oil (GCV of 43.8 GJ/tonne) and two tonnes of industrial diesel oil (GCV of 45.6 GJ/te) in 24 hours of steaming at 18 knots (distance travelled - 800 km) with average cargo load of 9000 tonnes (Ref. 7.38).

The diesel powered container ship as assumed to meet the same task, but with an efficiency 20 % greater than that of the steam turbine ship. Ref. 7.39 states that the oil fired diesel consumes about 145 g of fuel per brake horsepower hour while the heavy oil fired steam plant consumes about 190 g per shaft horsepower hour.

For the purposes of Table 8.4 the assessor's energy values were converted to a NCV basis assuming a NCV/GCV ratio for fuel oil and industrial fuel oil of 0.95 (Refs. 7.18, 7.19).

The coal fired ship is assumed to be of the single boiler Panamax type described in Section 7.3.2 with a cargo deadweight of 75,000 tonnes, speed of 14.5 knots (26,78 km/hr) burning coal with a GCV of 21.83 GJ/tonne. Coal consumption is taken to be 9 tonnes/hr.

By comparison, Ref. 7.40 estimates a TSEC for a coal fired 60,000 dwt bulk carrier using coal of about 27 GJ/tonne as being 0.17 - 0.18 MJ/tonne-km averaged over a round trip when the ballast distance is equal to the loaded distance. For the same task Ref. 7.28 estimates a TSEC for a 60,000 dwt oil fired ship using oil at 45 GJ/tonne as being 0.09 MJ/tonne-km.

For the purposes of Table 8.4 the assessor's energy values were converted to a NCV basis assuming a NCV/GCV ratio for fuel oil and industrial fuel oil of 0.95 (Refs. 7.18, 7.19).

The coal fired ship is assumed to be of the single boiler Panamax type described in Section 7.3.2 with a cargo deadweight of 75,000 tonnes, speed of 14.5 knots (26.78 km/hr) burning coal with a GCV of 21.83 GJ/tonne. Coal consumption is taken to be 9 tonnes/hr.

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For the purpose of Table 8.4 the assessor's energy values were converted to a NCV basis assuming a NCV/GCV ratio for black coal of 0.96.

3) Total Capital Cost.

The value of $ 16 * 10^6 in 1980 US$ for the container ship is directly from Ref. 7.38.
The value of $ 46 * 10^6 for the coal fired ship is from shipping industry sources and is about 15 % greater than an equivalent diesel ship.

4) Total O & M Cost.

For the container ships costs obtained from Ref. 7.38 and other sources are broken down as follows:

	1980 US $ * 10^6
Crew (31 people)	2
Port charges (in the range 10000 - 30000 $ per call with 30 - 70 calls per year)	1
Other ($ 275000 repairs and maintenance $ 600000 insurance, management	1.5
	4.5

Operating and maintenance costs (excluding fuel costs) for a coal fired ship are expected by the shipping industry to be marginally higher than for equivalent oil fired ships.

7.4 References

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8. ENHANCED OIL RECOVERY

8.1 Introduction

Not all the crude oil in underground reservoirs can be extracted. In the United States, only 32 % of the total amount of crude discovered had been recovered by 1978, leaving underground a volume approaching 300 billion barrels. The target of enhanced oil recovery processes is several time this figure when world-wide oil reservoirs, especially heavy oil deposits in Canada and Venezuela, are included.

Oil is displaced from the reservoir either by the gas cap formed over it or by the water vein displaced during the formation of the deposit or by both (figure 8.1).

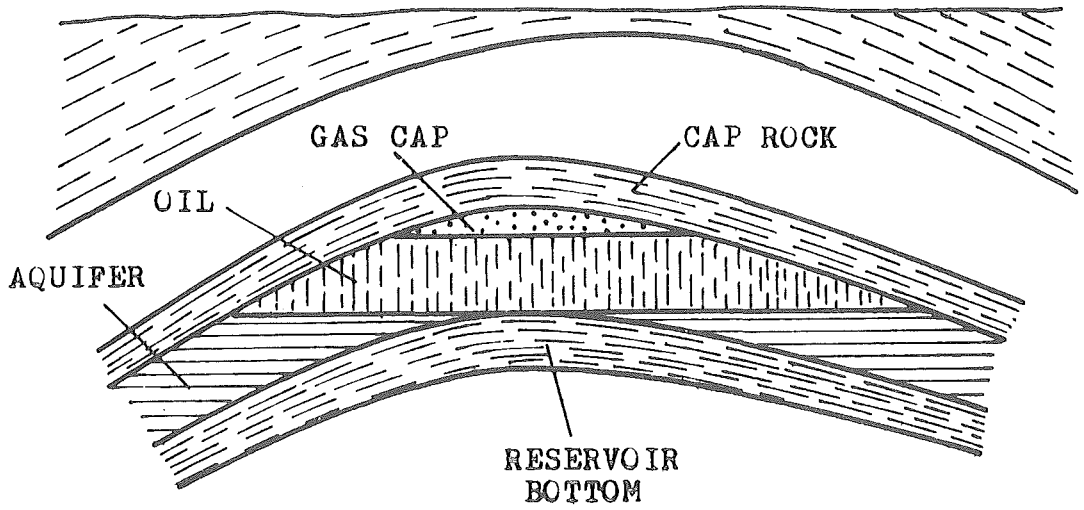

Figure 8.1: Classical representation of an oil reservoir. Vertical section

These forces have a recovery efficiency which is limited by many geochemical, geophysical, geological stratigraphic, sedimentological and reservoir engineering factors.

The recovery process can be thought as a sequence of three elementary steps, which develop at different geometric scales.

a) At the reservoir scale, the areal sweep efficiency, E_A is the fraction of the reservoir area that comes into contact with the displacing fluid. It depends on the flow geometry (that is, on the distribution of the producer wells, the injector wells and their flow rates), on the maximum allowable water cut in the production wells before they are abandoned, and especially on the mobility ratio between displacing fluid (water) and displaced fluid (oil). The term "mobility ratio" (M) is defined as:

$$M = \frac{\lambda \text{displacing fluid}}{\lambda \text{displaced fluid}} = \frac{K_w(S_{or})}{\mu_w} = \frac{\mu_o}{K_o(S_{wi})} \qquad (1)$$

where:

λ = mobility = $\frac{K}{\mu}$, $m^4/N.s$

$K_w(S_{or})$ = actual permeability to water, in the presence of residual oil, m^2

$K_o(S_{wi})$ = actual permeability to oil in the presence of interstitial water, m^2

μ_w = viscosity of the water in the reservoir, Pa.s = $N.s/m^2$

μ_o = viscosity of the oil in the reservoir, Pa.s = $N.s/m^2$

The greater the value of M, the more the water tends to permeate the oil, resulting in a self-accelerating effect.

Consequently, the value of the areal sweep efficiency, E_A, decreases as M increases, and this phenomenon occurs rather drastically when $M \gg 1$. As a first approximation it can be said that E_A decreases with the increase in oil viscosity.

Equation 1 clearly shows that an increase in the water viscosity (μ_w) and/or a decrease in the oil viscosity (μ_o) reduce the value of M, and therefore improve the areal sweep efficiency. Enhanced recovery processes which bring about such conditions are polymer flooding (an increase of μ_w) and thermal methods in general, which by increasing the reservoir

temperature, bring about a decrease in μ_o.

b) At the macroscopic scale the contact factor, or invasion efficiency, E_I is the ratio between the volume of reservoir actually invaded by the dispacing fluid and the volume of reservoir contained within the area delimited by the sweeping fluid front.

The contact factor depends on the heterogeneity of the reservoir, on the capillary-to-viscous forces ratio and on the mobility ratio M (equation 1).

As far as heterogeneity is concerned, it is necessary to distinguish a heterogeneity on a decimetric or metric scale (which, when $M>1$, lends to instability of the displacing fluid front and subsequent fingering, figure 8.2) and a 'large scale' heterogeneity, which can be identified with the presence of layers of different permeability in the reservoir rock (figure 8.3). In both cases the heterogeneity leads to the formation of 'islands' of rock containing oil that is no longer mobile except by imbibition, and therefore oil is lost in the reservoir.

c) At the microscopic scale, the 'microscopic displacement efficiency', E_D, represents the fraction of initial oil reserves which are recovered from those sections on the reservoir that came into contact with the displacing fluid.

The value, if E_D depends on the microscopic structure of the porous medium, increases with the fraction of pore volume initially occupied by the interstitial water; with the viscosity of water; and, with the reduction of the water/oil interface tension to zero. In other words, the displacing fluid must be completely miscible with the oil: all recovery processes in the miscible phase are based on these considerations.

Figure 8.4 shows the phenomenon of oil trapping. After the displacing front has passed, drops of residual oil remain which are isolated in the pore centers.

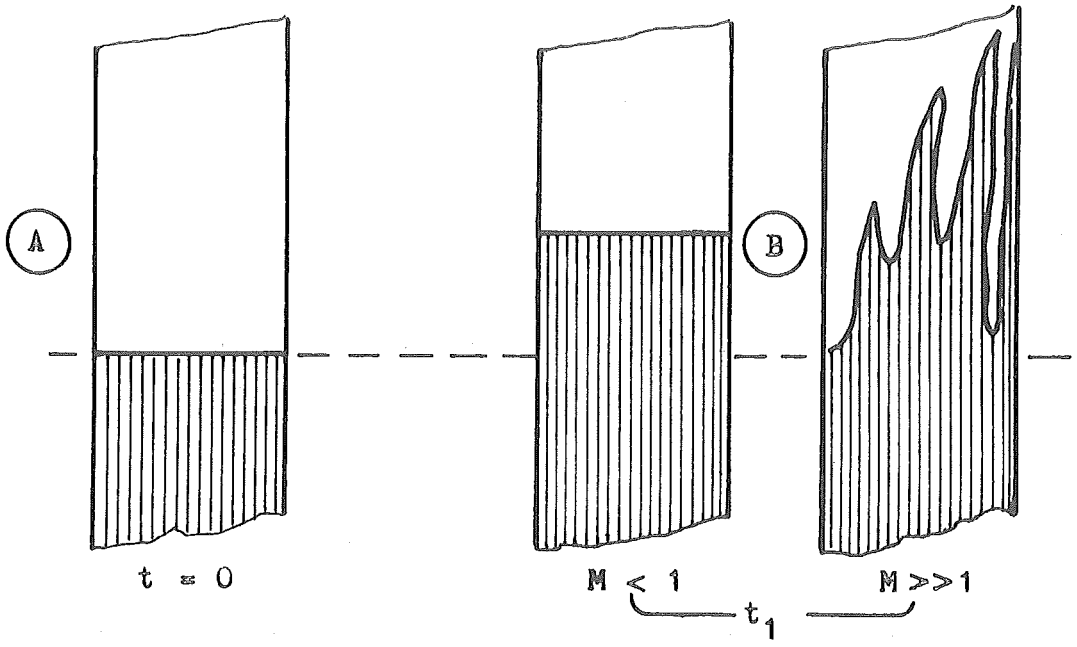

Figure 8.2: Fingering of water in oil as a result of the instability of the front
A. Initial situation at equilibrium
B. Situation after advancement of the water front

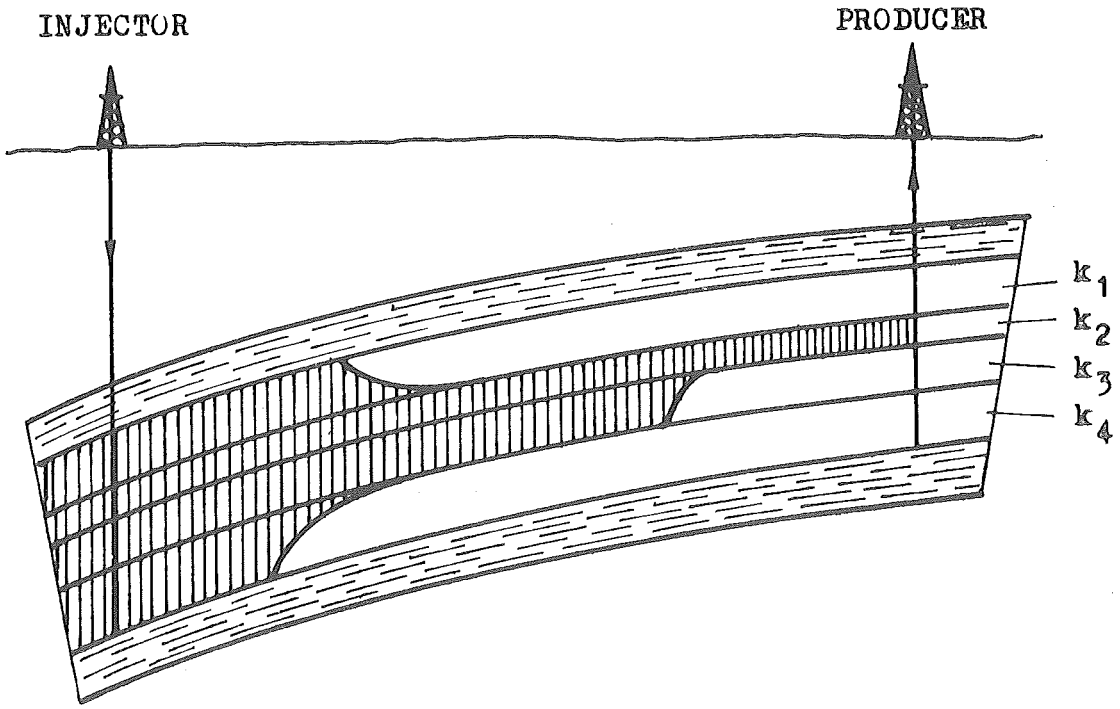

Figure 8.3: Advancement of water front in a stratified reservoir

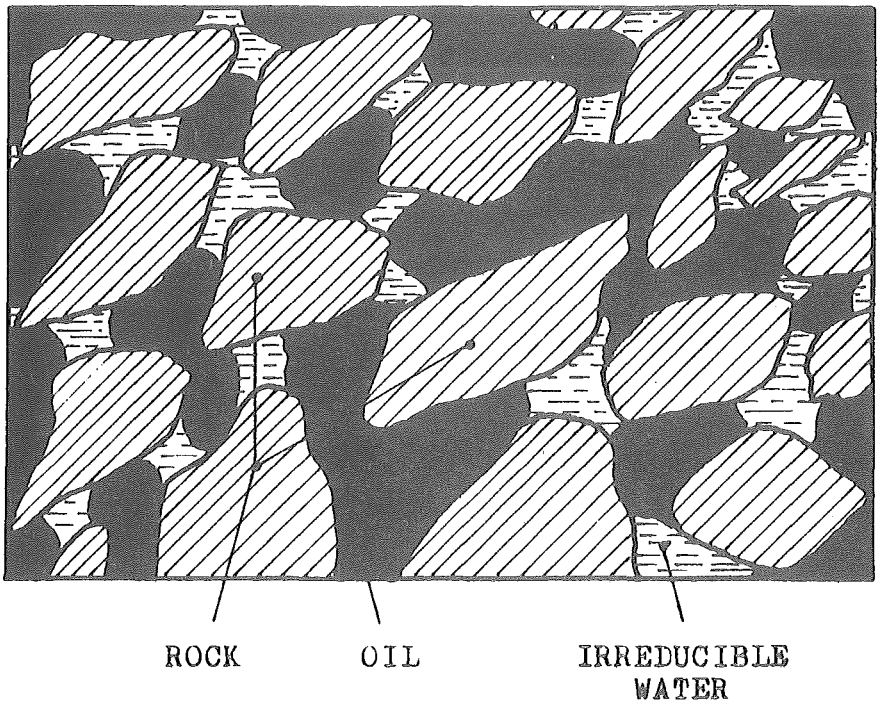

Figure 8.4: Fluid distribution in a porous medium
A. Initial reservoir conditions
B. Situation after water flooding

The percentage of reservoir oil that is displaced by water or by gas and can thus be produced from the wells (overall oil recovery efficiency, E_R) is given by the product:

$$E_R = E_D \cdot E_A \cdot E_I \qquad (2)$$

For each reservoir and for each recovery process (primary and secondary), the value of E_R can be determined by simulating the process on a numerical reservoir model.

As an example, typical values of coefficients which appear in equation 2 for recovery by water flooding are:

E_A	-	areal sweep efficiency	: 0.7 to 0.9
E_I	-	contact factor	: 0.6 to 0.9
E_D	-	microscopic displace efficiency	: 0.4 to 0.6

from which it can be deduced:

E_R	-	overall oil recovery efficiency	: 0.15 to 0.50

It should be noted that about half of the oil retained in a reservoir has been trapped in the pores, and the other half has been contained in rock "islands" by-passed by the water.

Many enhanced oil recovery processes have been studied (figure 8.5). Only the more common or promising (tables 8.1, 8.2) have been characterized.

The different processes usually are not in competition; they simply cope with different reservoir conditions (figure 8.6, 8.7).

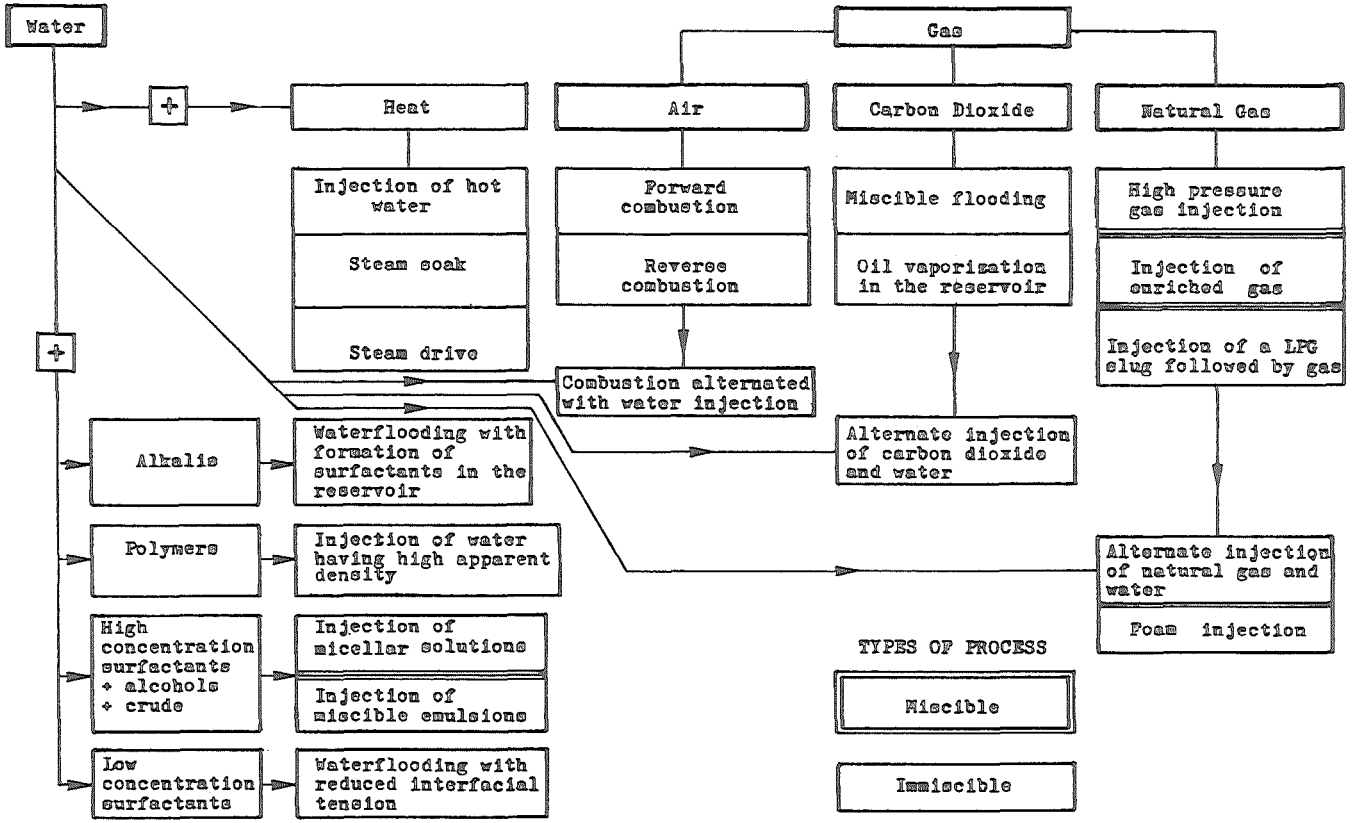

Figure 8.5: Processes for Increasing Secondary and Tertiary Oil Recovery from Reservoirs.

TABLE 8.1 - Enhanced Oil Recovery - Situation in North and South America, 1979

PROCESS (*)	Ranges of applicability as a function of reservoir depth	Expected increase in oil recovery (% of original oil in place)		Oil produced (1979)			Percentage of total production (**) (1979)		Number of active projects (US, only)	Production cost range	Maximum annual additional production (US only, 1995)
	m	From	To	bbls/day	m^3/million year	percent	Americas	World		$ 1980	10^6 m^3/yr
Miscible phase gas injection (hydrocarbons, CO_2, etc.)	800-3000	45	70-75	87,700	5.08	15.3	0.57	0.14	34	19-31	70
Steam injection (steam soak, steam drive)	0-800	10	60	465,500	27.02	80.9	3.02	0.75	133	13-20	50
In situ combustion	0-1300	40	70	19,600	1.14	3.4	0.13	0.03	17	17-28	
Miscellar/solutions	0-1700	45	80	2,400	0.14	0.4	0.02	-	14	26-37	85
Thickened water	0-3000	30	40	2,400	0.14	0.4	0.02	-	28	14-19	
TOTALS	-	-	-	575,200	33.38	100.0	3.74	0.92	226		

(*) The water injection process, which can increase the oil recovery from 10-20% to 30 ÷ 50%, produced nearly 50% of 1979 US oil ($4.2.10^6$ bbl/day).

(**) Based on: 1979 oil production in the Americas: 15,390,400 B/D = 893.2 million m^3/year

1979 world production: 62,588,400 B/D = 3,623,3 million m^3/year

TABLE 8.2 - Enhanced Oil Recovery Processes (excluding water injection) underway in 1979 outside the American Continent

Type of process	Country	Field	Year begun	Production rate (B/D)
Caustic flooding	West Germany	Dickel	1980	unknown
	USSR	Shaim	unknown	unknown
Polymer flooding	West Germany	Orrel-Sud	1975	unknown
	West Germany	Hankensbüttel	1977	unknown
	USSR	Aslansk	unknown	unknown
	USSR	Buzovin	unknown	unknown
	USSR	Orlyansk	unknown	unknown
Surfactant flooding	USSR	Samotior	unknown	unknown
Miscible, natural gas	Algeria	Hassai Messaoud	1964	60,000
	Libya	Intisar D	1969	100,000
	Poland	Folusz	1977	20
	USSR	Stavropol	unknown	unknown
Miscible, CO_2	Hungary	Budafa	1969	250
	Hungary	Kiscsemi	1974	unknown
	Hungary	Lovaszi	1975	unknown
	Hungary	Nagylengyel	1979	unknown
	France	Grenade	1979	10
	USSR	Tuimazy	unknown	unknown
Micellar/polimer	France	Chateaurenard	1978	60
Hot-water flooding	West Germany	Emlichheim	1967	2,700
Steam soak	Indonesia	Duri	1967	22,000
	West Germany	Rühlermoor	1976	unknown
Steam drive	Indonesia	Duri	1976	34,000
	Holland	Schoonebeck	1972	1,600
	West Germany	Georgsdorf	1975	900
	West Germany	Rühlertwist	1978	1,300
	France	Lacq Supérieur	1977	380
	USSR	Yarega	1968	2,600
	USSR	Aspheron	unknown	unknown
	USSR	Sakhalin	unknown	unknown

TABLE 8.2 - continued

Type of process	Country	Field	Year begun	Production rate (B/D)
In situ combustion	Romania	Suplacu de Barcau	1964	5,800
	Romania	Suplacu de Barcau	1964	5,800
	Romania	Balaria	1975	60
	Hungary	Demjèn	1973	20
	USSR	Krasnodar	unknown	unknown
	USSR	Russkoye	unknown	unknown

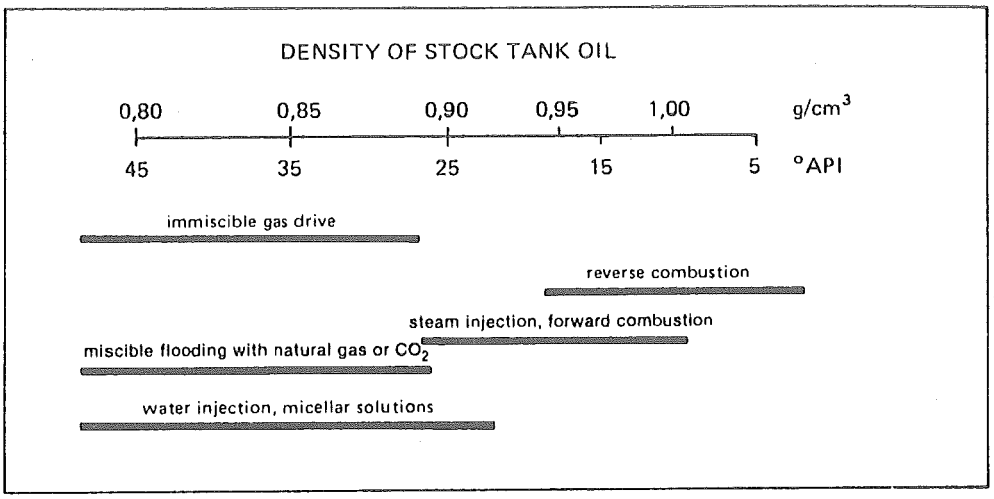

Figure 8.6: Ranges of applicability of enhanced oil recovery processes as a function of the density (or API gravity) of the oil

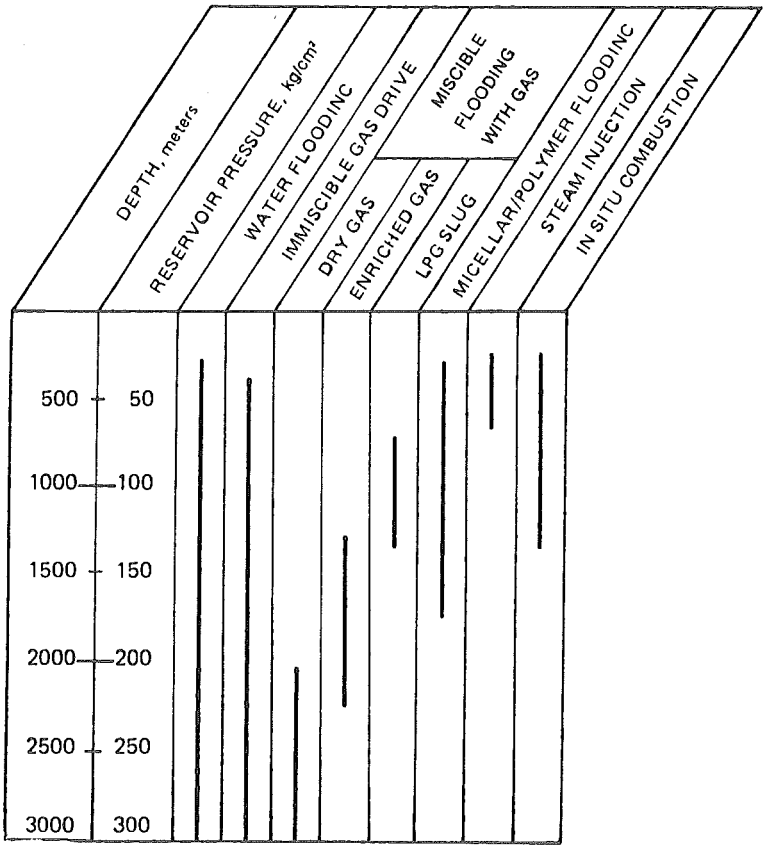

Figure 8.7: Ranges of applicability of the various enhanced oil recovery processes as a function of reservoir depth

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8.2 Enhanced Oil Recovery with Steam Injection

Steam injection is performed according to two different techniques, that is:

- alternate cycles of steam injection and oil production from the same well (huff and puff, or steam soak), figure 8.8

- continuous steam injection (steam drive), figure 8.9

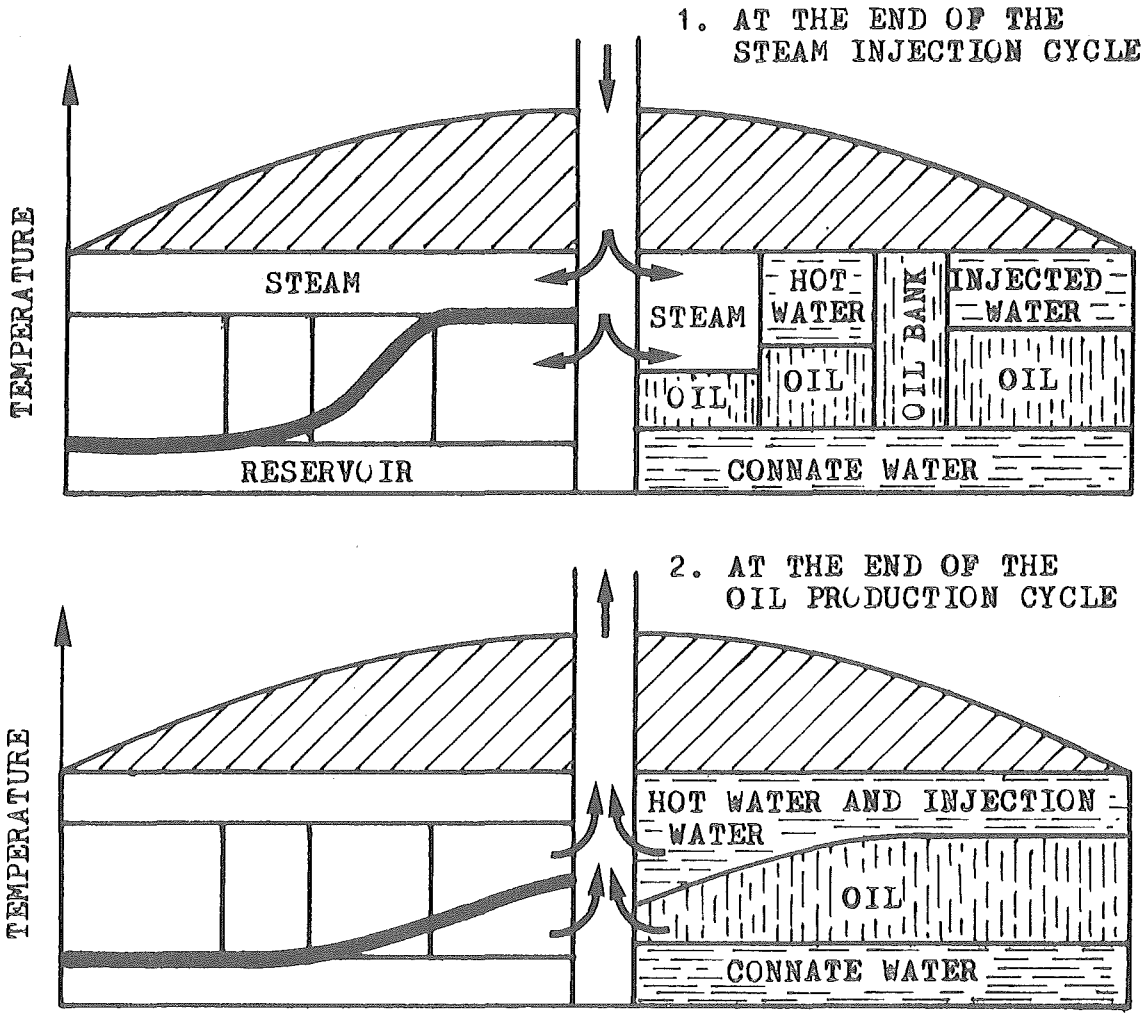

Figure 8.8: Schematic diagram of fluid and temperature distributions in the reservoir in a steam soak (also called 'huff and puff') process

In the strict sense of the term, steam soak should not be considered an enhanced oil recovery process, but rather a method of stimulating the productivity of the wells: in fact there is no increase in oil recovery, but only a reduction in the time needed to deplete the reservoir. The injected steam heats the reservoir rock near the well, displacing forward the fluids contained therein. In the successive phase of production, the oil flows towards the well, undergoes a reduction in its viscosity due to heating, which causes an increase in the productivity index of the well.

Alternating cycles of injection and production are continued until the economic limit of the well's oil flow rate is reached.

On the other hand, continuous steam injection is a true enhancement oil recovery process, and its considerable success can be attributed to the fact - which is obvious, but not always considered - that the transmission of heat occurs even in those layers which are impermeable to fluid flow. Whereas the lack of permeability of a layer prevents fluid flow (and thus mass flow), it does not prevent the flow of heat: the thermal conductivity of rock is not affected very much by its lithology and fluid content.

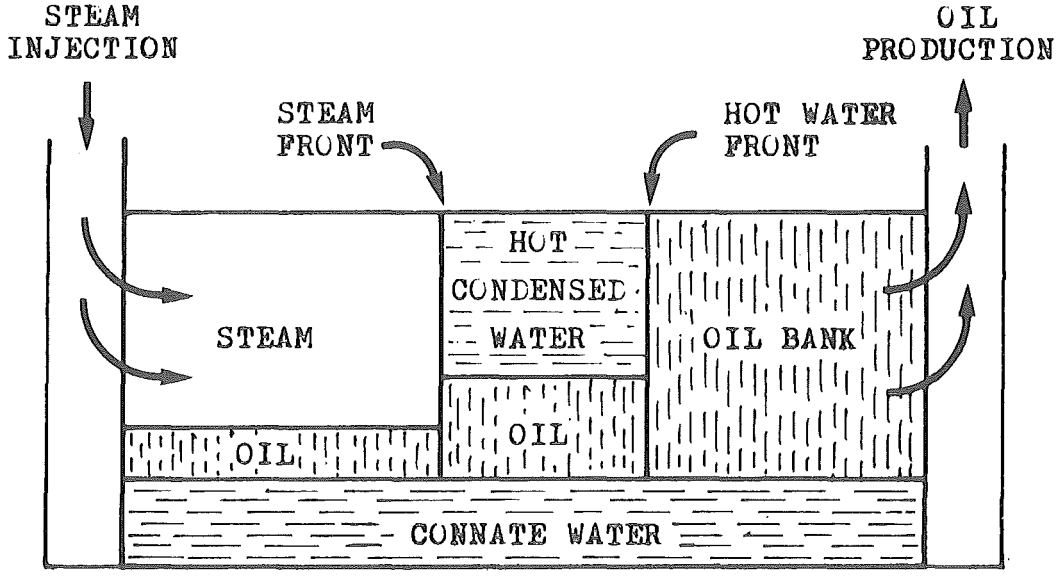

Figure 8.9: Schematic diagram of fluid distribution in the reservoir in the case of steam drive

As a result, the steam only has to flow through a limited number of permeable intercalations in order for the whole reservoir to become heated by heat conduction. This enables the oil to become fluidized and displaced (by imbibition or by dissolved gas drive) even from those "pockets" of the reservoir that had not been in contact with the steam.

Research efforts aim:

(1) To improve the recovery efficiency of the process by: increasing the size of the steam zone through use of foams, gels and polymers; increasing displacement in the hot water zone through the use of chemical additives; examining means for optimizing the process, including analyzing the effects of steam quality and rate; and, the use of steam/inert gas mixtures.

(2) To extend the steam flood process to more difficult reservoirs, such as: deeper reservoirs (below 800 m) through use of downhold steam generation; lighter oil (20-30° API) reservoirs; and, tar sands.

Summarized in table 8.3 below are the data for enhanced oil recovery by steam injection:

TABLE 8.3 - Enhanced Oil Recovery by Steam Injection

Country	Contents of the oil Reservoir	Expected Oil Recovery	Total Project Cost	Annualized Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	$10^6 m^3$	%	10^6 $	$/bbl	$/bbl	$/bbl
Italy	2	15-19	9	3-6	6-9	11-12

Assessor

Tosato, G., Ente Nazionale Idrocarburi; Piazzale Enrico Mattei 1, Rome, Italy

Notes

(1) The process is already in operation.

(2) Contents of the Oil Reservoir

This was the initial oil content of the reservoir in the Valle Cupa (Italy). Up to 1964, 7.8 % has been recovered by conventional methods. It is hoped that another 15 to 19 % will be recovered by the steam injection techniques.

(3) Total Project Cost

Fractions of the total project cost of $ 9 . 10^6 are:

data collection	4 %
reservoir engineering study	5 %
pilot construction	81 %
process test	10 %

(4) Variable Operating and Maintenance Cost

The variable O&M cost can be split as follows:

Steam (for 30 $/bbl oil price)		2-3 $/bbl
Financial cost:	taxes	2 $/bbl
	royalties	4 $/bbl
	windfall profits	3 $/bbl

8.3 Enhanced Oil Recovery with in Situ Combustion

There are two different technologies for enhanced oil recovery by means of partial combustion in the reservoir: forward combustion and reverse combustion. Only the former has had a certain success; reverse combustion has been limited to a few pilot field projects, especially in tar sands.

In forward combustion the combustion front in the reservoir advances in the same direction as the fluids moving in the formation. In practice, air is injected into the reservoir through injection wells, and the oil in the formation is ignited.

In order for the combustion to be maintained and the combustion front to advance in the formation, the reservoir rock must be permeable to air and to combustion gases downstream of the front.

The combustion gases heat the oil downstream of the front. In this oil there occur complex phenomena of cracking and partial distillation; the products resulting from cracking and distillation condense downstream forming a bank of light oil (figure 8.10) which displaces forward and dilutes the formation oil. The formation water vaporizes and contributes to the production of oil as a steam drive.

In reverse combustion, the fire is ignited in the reservoir near the production well, and the air supporting the combustion is injected from the opposite injection well. In this way the combustion front advances in the direction opposite to the injected air. This practice is appropriate when the viscosity of the reservoir oil is so high that its mobility is practically zero.

In both cases, the crucial point is to maintain the combustion and the regular advancement of the front inside the reservoir.

In any event, in order to ensure the continuity of the process, it is necessary to have a very small spacing between the injection and production wells. This restricts the applicability of

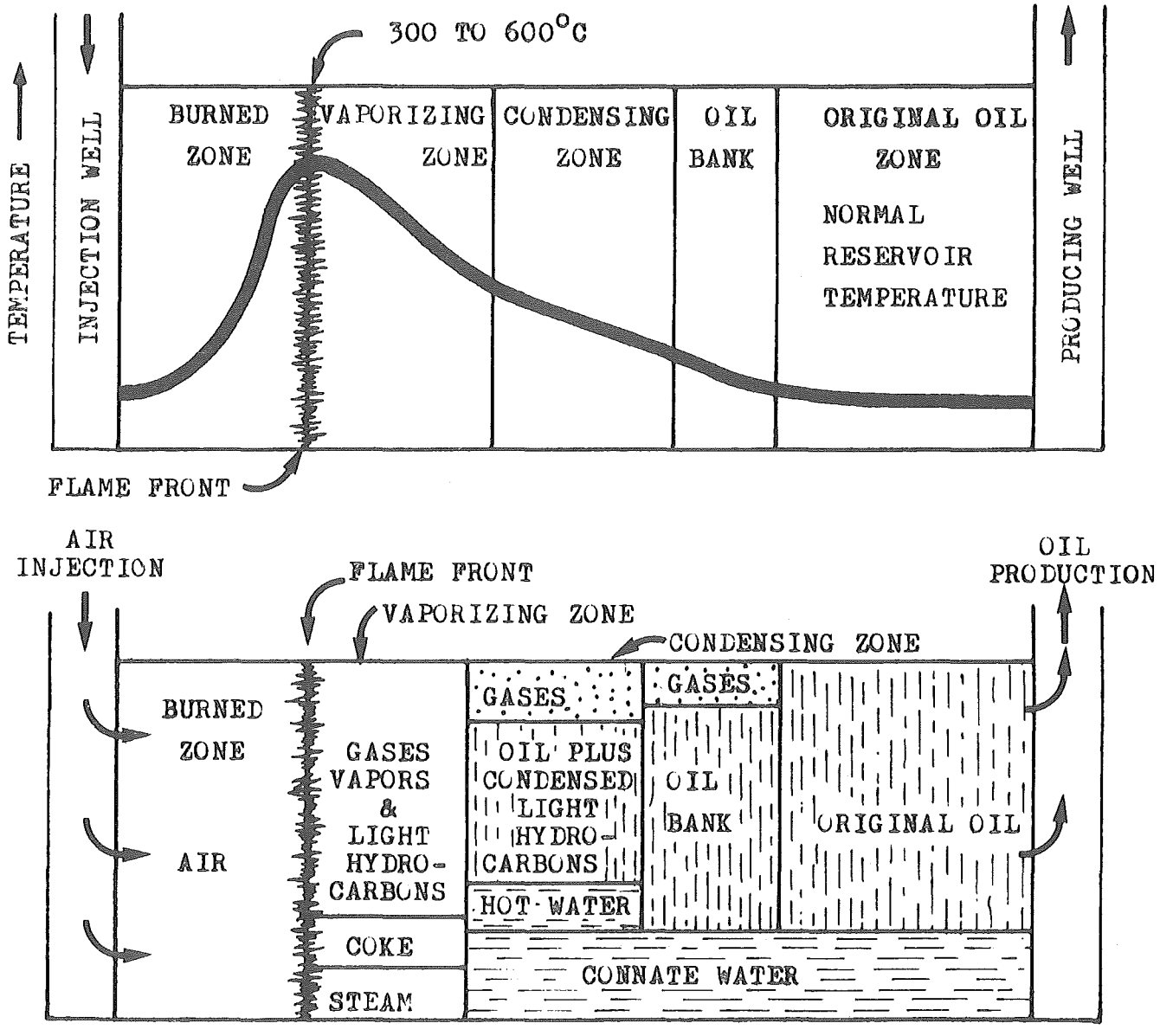

Figure 8.10: Schematic diagram of fluid and temperature distribution in a reservoir exploited by forward combustion

underground combustion to reservoirs at shallow depths, which have a limited unit cost for drilling and well completion. There is also a significant amount of corrosion in the production wells, due to the effect of the combustion gases which at times have a high content of SO_2 and SO_3. This requires the use of special steels, particularly in the tubing and surface separators.

A more recently developed method for controlling temperature and reducing air/oil ratios is to use forward combustion and water. The injection of water cools the combustion zone by vaporization and the resulting hot vapor moves heat through the reservoir ahead of the combustion front. While this process is still economically unproven, it is reported to be promising in a series of small pilot tests.

In situ combustion is still considered risky and only partly proven. The current objectives for in situ combustion are to gain further understanding of this process and to improve its efficiency and reliability. Research purposes are:

(1) to test means for increasing the vertical sweep efficiency of the combustion front;

(2) to demonstrate the economics of the simultaneous water-air process;

(3) to extend the combustion process to high-viscosity and tar sand formations.

TABLE 8.4 - Technical and Economic Data - Enhanced Oil Recovery by in Situ Combustion

Country	Inputs		Net Incremental Production	Total Project	Annualized Capital Cost	Fixed O&M Cost	Variable O&M Cost
	Combustion Air	Self combustion of Oil in Place					
Unit	$\frac{m^3(air)}{m^3(centre\ output)}$	% of oil in place	% of remaining oil in place	10^6 $	$/bbl	$/bbl	$/bbl
Italy	500-1200	30-50	28-39	9.7	3-6	6-9	15-25

Assessor

Tosato, G., Ente Nazionale Indrocarburi, Piazzale Enrico Mattei 1, Rome, Italy

Notes

(1) Enhanced oil recovery by in situ combustion is tested on the Belleview field in Louisiana (United States). The project area is about 25 ha, in which 14 wells have been drilled to an average depth of 15 m.

(2) Total Capital Cost

The complete project costed to the operator, Cities Service Inc., about 8.2 . 10^6 $_{78}$. This corresponds to 9.7 . 10^6 $_{80}$.

(3) Variable Operating and Maintenance Cost

Variable O&M cost can be split as follows:

Cost for air injection	6-11	$/bbl
Financial costs: taxes	2	$/bbl
royalties	4	$/bbl
windfall profits	3	$/bbl

The cost for air injection have been calculated for a crude price of 30 $/bbl.

8.4 Enhanced Oil Recovery with Carbon Dioxide Flooding

Once it is injected into the formation, CO_2 dissolves in and saturates the oil. Due to vaporization, the excess CO_2 extracts the medium-light fractions of the residual oil, forming a CO_2 slug rich in hydro-carbons; this slug is miscible with both the reservoir crude and the subsequently injected CO_2 (figure 8.11).

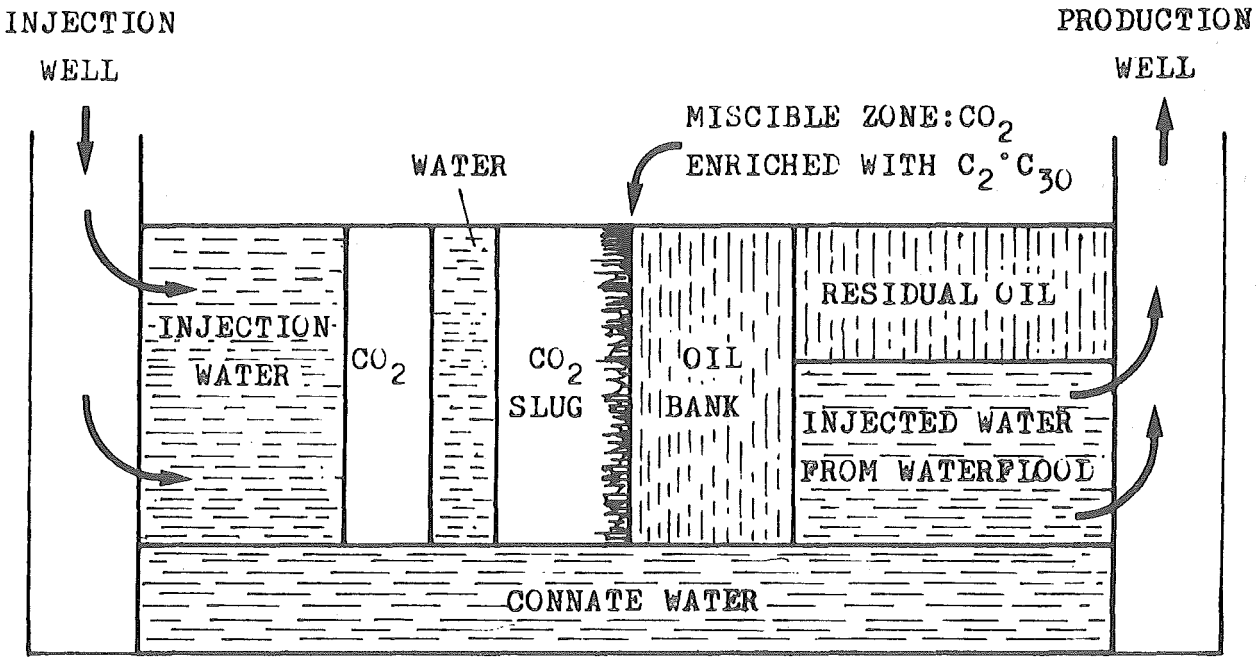

Figure 8.11: Schematic diagram of fluid distribution in the reservoir, in the case of miscible CO_2 flooding alternated with water slugs

It should be pointed out that it is not necessary for the injected CO_2 to have a high degree of purity in order to reach miscibility with the reservoir oil. It is even possible (and in fact there

have actually been cases) to have miscible processes using, as the displacing fluid exhaust gas from internal combustion power generators or boilers (flue gas), consisting of only 11-12 percent CO_2 and 85-88 percent nitrogen.

Even in those reservoirs where the pressure is not sufficiently high to guarantee miscible flooding, the injection of CO_2 in the immiscible phase may have positive effects on oil recovery: this is the case of medium-heavy crude oil reservoirs at low depths. In fact, when the CO_2 dissolves in the crude, it causes a considerable reduction in the viscosity and an increase in its volume; these factors interplay to produce an increase in recovery due to water flooding. The weakness of both processes lies in the high mobility ratio between the injected gas and the reservoir oil: water slugs, alternated with CO_2 slugs, are used to reduce - by means of relative permeability phenomena - the mobility of the CO_2 in the reservoir.

After steam injection, CO_2 flooding in miscible and immiscible phases (in the latter case especially as flue gas) represents the most promising "nonconventional" enhanced oil recovery process. The main problems which limit its use are:

a. The difficulty of finding the large quantities of CO_2 necessary for these projects.

b. The high investment required to gather, dehydrate, compress, and transport the CO_2, at times over great distances.

c. The problems related the corrosion occuring both on the surface equipment and especially in the wells, due to the presence of a highly aggressive gas such as CO_2 accompanied in the wells by brines having varying degrees of salinity.

TABLE 8.5 - Technical and Economic Data - Enhanced Oil Recovery by Carbon Dioxide Flooding

Country	Annual Energy Input for CO_2 Separation and Compression	Net Incremental Production	Annualized Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	PJ	% of remaining oil in place	$/bbl	$/bbl	$/bbl
Italy	-	15-19	2-5	3-7	21-26
Norway	72	40	-	11-16	11-16

Assessors

Italy:- Tosato, G., Ente Nazionale Idrocarburi, Piazzale Enrico Mattei 1, Rome

Norway:- Ormhaug, T., Institute for Energy Technology, N-2007 Kjeller, Norway

Notes

(1) Systems Description

The enhanced oil recovery method, described by the Norwegian project participant, uses simultaneous injection of CO_2 in the lower half and water in the upper half of the oil reservoir. The injection period lasts 1000 days and is followed by a 700 days period of chase water injection into the reservoir. Figure 8.12 shows the rate of oil recovered from the reservoir as a function of time.

Note that during the first two years of CO_2 injection, no oil is recovered.

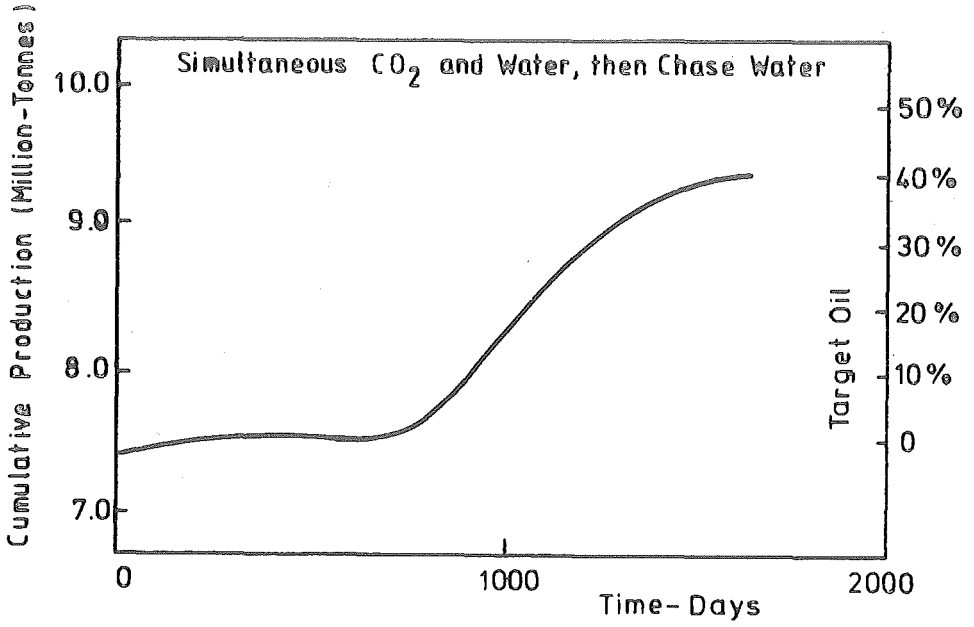

Figure 8.12: Oil Recovery resulting from a CO_2 Injection Strategy

(2) Annual Energy Input for CO_2 Separation and Compression

Norway - CO_2 will be injected only in the first 3 years of the 6 year production period. The calculated CO_2 requirement during this period is 1.1 tonne per tonne of oil recovered. However, also a considerably higher CO_2 demand (3.5 tonnes per tonne of oil recovered) seems possible.

Italy - The volume of CO_2 injected for the recovery of 1 bbl of oil ranges from 10-13 Mcf/bbl.

(3) Variable Operating and Maintenance Cost

The variable O&M cost given in the Italian characterization can be split as follows:

CO_2 requirements	12-16	$/bbl
Financial cost: taxes	2-3	$/bbl
royalties	4	$/bbl
windfall profits	3	$/bbl

8.5 Enhanced Oil Recovery with Micellar Flooding

The micellar flooding is a miscible process in the liquid phase. The use of surfactants (2-8%) formed by a hydrophilic nucleus and an oleophilic tail, allows the formation of a stable microemulsion of water and oil. This microemulsion is miscible in all ratios of both the crude and the water trapped in the pores of the reservoir. If thickened water is injected downstream afterwards all the oil bank can be displaced and recovered.

While laboratory studies and core floods show high recoveries, field test results have performed more poorly than expected - the ratio of chemicals injected to oil recovered has been higher than initially assumed.

The field tests are being conducted to develop a better understanding of the behaviour of the complex surfactant systems under reservoir conditions. In particular to:

- test the effectiveness of alternative surfactant and micellar slugs and flooding systems;

- examine the feasibility of extending the process to more viscous oil, lower-permeability formations, higher temperatures ($\geqslant 90^{o}C$) and higher salinity content ($\geqslant$50,000 ppm).

TABLE 8.6 - Technical and Economic Data - Enhanced Oil Recovery by Micellar Flooding

Country	Net Incremental Production	Total Project Cost	Annualized Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	% of remaining oil in place	10^{6} $	$/bbl	$/bbl	$/bbl
Italy	30-43	11.8	5-9	5-9	23-26

Assessor

Tosato, G., Ente Nazionale Idrocarburi, Piazzale Enrico Mattei 1,
Rome, Italy

Notes

(1) The Italian characterization summarizes the data of an enhanced oil recovery project in Illinois (U.S.A.). On a project area of 35 ha, 13 wells are planned for the oil recovery from a field with an average depth of 880 m. The process of enhanced recovery by micellar flooding is the most recent and least proven of the enhanced oil recovery techniques.

(2) The micellar solution which is injected into the oil field contains (per barrel of incremental oil)

1.5 lb polymer
0.5 bbl surfactant, of which:
9 lb sulfurates
2 lb alcohol
35 lb oil

(3) Variable Operating and Maintenance Cost

The variable O&M cost can be split as follows:

Surfactant/polymer		12-15	$/bbl
Financial cost:	taxes	4	$/bbl
	royalties	4	$/bbl
	windfall profit	3	$/bbl

8.6 Enhanced Oil Recovery with Modified (Thickened) Water Flooding

The overall oil recovery, E_R that can be obtained through water injection is principally controlled by two factors:

1. Interfacial tension, between water and oil in the reservoir, which is rather high (0.02 to 0.04 N/m). As a consequence, the microscopic displacement efficiency, E_D is generally not very high.

2. Oil viscosity, in the case of heavy crudes, may be many times higher than that of water. The result is that the mobility ratio, N, between water and oil, is, in the case of heavy crudes, also very high with a low areal sweep efficiency E_A (figure 8.12) and a low contact factor, E_I.

In the attempt to improve oil recovery, experiments have been carried out, mainly on a pilot scale, of modified water floods.

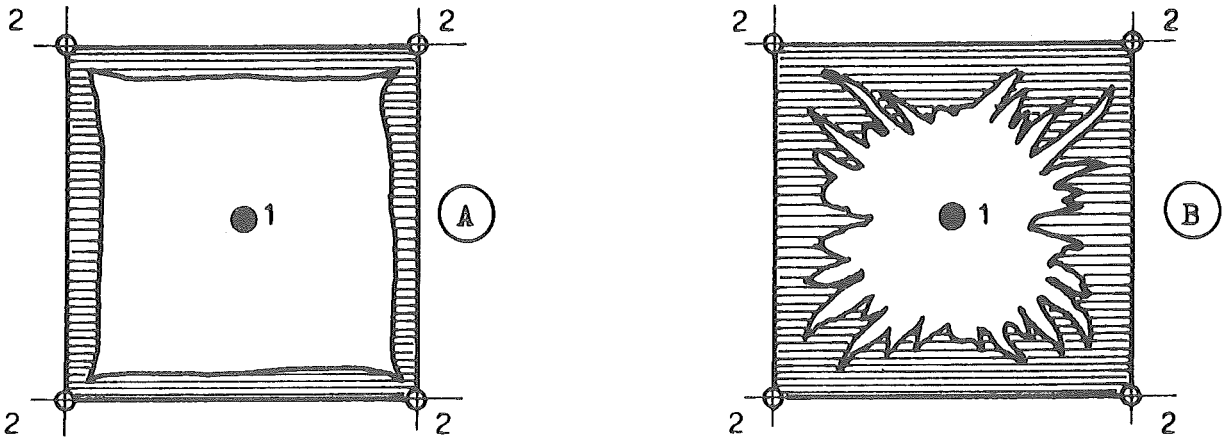

Figure 8.13: Five spot pattern. Influence of the water/oil mobility ratio on the areal sweep efficiency, E_A

Some of them increase the viscosity of the injected water by adding polymers containing a long linear chain, along which there are polar groups (partially hydrolyzed polyacrilamides,

ethylene oxide polymers, biologically hydrolized polysaccharides).

Aqueous solutions of these polymers have a non-newtonian behaviour: that is, their apparent viscosity depends on the shear rate. In very small capillaries - like the pores of the reservoir rock - the viscosity of these solutions becomes (even in polymer concentrations of some hundred ppm) many times higher than that of water. Therefore, it is possible to create slugs of thickened water, having a lower mobility than that of the oil to be swept. This thickened water, followed by normal water, enables areal sweep efficiencies and contact factors to be obtained that are much higher than those for water injection alone.

The main problem which arises is the effect of high salinity formation waters. In the presence of a fluid having a high ionic concentration, the molecules of the polymer tend to form "balls", because of the neutralization of their polar groups. This results in a rheological behaviour (and an apparent viscosity of the thickened water) that soon approaches that of pure water.

Two questions are addressed by pilot tests:

- does the effectiveness of polymers currently available in the market, survive the many months and years of contact in the subsurface with reservoir rock, fluids and reservoir ambience?

- is the target for polymer flooding as large as postulated, e.g. is the sweep of reservoirs with slightly unfavorable mobility ratios as poor as predicted by theoretical and model analyses?

TABLE 8.7 - Technical and Economic Data - Enhanced Oil Recovery by Modified Water Flooding

Country	Net Incremental Production	Total Project Cost	Annualized Capital Cost	Fixed O&M Cost	Variable O&M Cost
Unit	% of remaining oil in place	10^6 $	$/bbl	$/bbl	$/bbl
Italy	4	4.73	0	2-3	19-23

Assessor

Tosato, G., Ente Nazionale Idrocarburi, Piazzale Enrico Mattei 1, Rome, Italy

Notes

(1) The characterized modified water flooding technique is also known as polymer flooding. The given data are valid for a project that is carried out by Kewanee Oil Co. on the Stanley Stringer Field in Oklahoma (U.S.A.). The project area is 16 ha and the oil field depth averages to 880 m.

(2) Annualized Capital Cost

If polymer flooding is considered as a supplement to water flooding, no incremental investments are required. Otherwise, the additional annualized capital cost will be 3-7 $/bbl.

(3) 3 to 5 lb polyacrilamides are injected for the recovery of 1 bbl incremental oil.

(4) The variable O&M cost can be split as follows:

Polymer	9-13	$/bbl
Financial cost: taxes	3	$/bbl
royalties	4	$/bbl
windfall profit	3	$/bbl

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